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An Analysis of Recent Electric Utility Rate Increases

Temple, Barker and Sloane, Inc, Wellesley Hills, Mass

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THE ENERGY AND ENVIRONMENT GROUP
TEMPLE, BARKER & SLOANE, INC

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AN ANALYSIS OF RECENT ELECTRIC UTILITY RATE INCREASES

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Finally, responsibility for any errors and ommissions remains with the authors.

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I. INTRODUCTION

While there has been little doubt that electric bills increased during 1974, it has been unclear how large these increases have been and how important each of a number of causal factors has been. There exist a number of annual surveys of electric rates and rate increases, but these studies prescribe different methodologies for evaluating rate increases, utilize different measures for determining the amount of increase, and often reach different conclusions. Appendix A summarizes several recent rate studies.

The importance of a cogent analysis of rates became obvious in 1974. The 1960s were a period of generally decreasing costs for electricity. The early 1970s were a period of steady, but small, rate increases. During 1974, however, a number of factors led to a quantum increase in fuel costs. A high rate of general price inflation, difficult capital market conditions, and energy conservation all contributed to a rapid rate of increase in consumer charges for electricity. In addition, many public policy-makers and utility executives cite expenditures for environmental reasons as a major contributor to recent electric rate increases.

In order to determine the magnitude of the costs associated with environmental clean-up, the Environmental Protection Agency (EPA) contracted with Temple, Barker & Sloane, Inc. (TBS) to undertake an independent investigation into the total amount of rate increases during 1974 and to analyze the underlying reasons for these increases. This report summarizes the conclusions reached by TBS after

analyzing a nationwide sample of utility systems representing more than 50 percent of the investor-owned sector of the electric utility industry.[1] Appendix B details these sampling procedures.

The TBS methodology focused on the overall increase in revenues per kilowatt hour (i.e., average consumer charge) and the proportion associated with each of the following cost factors:

- increases in fossil fuel prices;
- changes in the mix of fuels caused by
  - --environmental requirements (e.g., reductions in sulfur content and/or coal-to-oil conversions),
  - --unavailability of primary fuel (e.g., natural gas curtailments), and/or
  - --other economic and public policy reasons (e.g., oil-to-coal conversions);
- general price inflation;
- increases in the rate of interest on long-term debt and the dividend rate on preferred stock;
- higher rates of return required to attract adequate capital;
- reductions in the demand for electricity (i.e., energy conservation); and
- additions of pollution control equipment.

The remainder of this report highlights the conclusions reached during this analysis.

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[1] *Investor-owned utility systems represent nearly 80 percent of the total electric utility industry in terms of generating capacity (kilowatts) and/or energy sales (kilowatt hours).*

II. EXECUTIVE SUMMARY

1974 saw an unprecendented increase in the cost of electricity. Based upon its nationwide sample of investor-owned utility systems, TBS estimates that total industry revenues from electric operations may have exceeded $40 billion in 1974, up approximately $9 billion from 1973. On a per kilowatt hour basis, average consumer charges increased 30 percent. Thus, a kilowatt hour increased in price from 19.7 mills (i.e., less than 2 cents) to 25.7 mills.

Nearly 60 percent of the increase in rates can be directly linked to the increase in the cost of the fuels burned by utility systems. The remaining 40 percent resulted from increases in the non-fuel costs of service.

Increases in Fuel Costs

The primary cause of these increases in revenues and consumer charges was the rapid escalation in all fossil fuel prices following the Arab oil embargo in late 1973. Fossil fuel prices were up more than 86.2 percent during 1974. The principal contributor to this rate of increase was oil prices, which increased from less than $5 per barrel to more than $11 per barrel--an increase of more than 135 percent. Next in importance was the price of coal, which increased 68.5 percent during the year, due to increasing demand and to the anticipation of a long coal strike near the end of the year. These factors led to a quantum increase in the price of coal purchased in the spot market. Increases in the cost of natural gas were only 33 percent, due to the restraint imposed by interstate price regulation.

A shift in generation mix toward hydro-electric and nuclear fuel somewhat mitigated the impact of these

increases in fossil fuels. Overall, however, the fuel component of electric rates increased by 72.9 percent.

Increases in Non-Fuel Costs

Costs of electric service other than fuel increased only 16.8 percent, slightly more than one-half the overall rate. Within this broad category, the most important increase was in the cost of money. Financing problems, in terms of both the higher rates and the availability of financing, plagued the industry. Continued needs for capital, regulatory delays in granting general rate increases, and energy conservation forced many utility systems to operate under severely constrained circumstances during 1974.

These factors, coupled with a depressed stock market, led the industry to seek assistance from the Federal government in the form of changes in regulatory policies--for example, toward more timely granting of rate requests, toward more favorable tax policies and accounting procedures, and toward relaxed environmental requirements.

While difficult to quantify, each of the above factors exacerbated the pressures that resulted from the routine pass-through of fuel costs. Since a request for a general rate increase requires public hearings and explicit approval by the appropriate regulatory commission, consumers, outraged by their inability to cope with double digit inflation, campaigned vigorously to control these increases in electric rates. While their actions were successful in delaying rate increases during 1974, general rate relief is inevitable if the electric utility industry is to remain viable.

Perhaps the best measure of this need for a change in regulatory procedures can be found in the relative trends in the long-term interest rate and the rate of return on common equity within the industry. While the embedded interest rate for long-term debt more than

doubled during the 1960-1974 period from 3.5 to 7.1 percent, the return on common equity actually declined from 10.9 to 10.6 percent. If these trends continue, the nation's most capital intensive industry will find it increasingly difficult to finance future generation capacity and pollution control requirements.

Impacts by Customer Type and Geographic Region

The dramatic increases in electric rates were not evenly distributed by type of customer, nor by geographic region. While the average consumer charge was increasing by 30 percent, the average charge for residential customers increased by only 23 percent, as compared to the 33 percent increase for commercial and industrial customers. These differences in rates of increase follow from the predominant role that fuel costs have played overall. Since fuel adjustment clauses generally allocate fuel costs equally to all kilowatt hours used, their burden is greatest on the largest customers due to the declining block structures employed in most rate schedules.

Consumers along both the Atlantic and Pacific coasts were the most seriously affected by the increase in electric rates. Since the highest inflationary pressure came from fossil fuels in general and from oil in particular, the regions that depended on oil for a significant proportion of their generation were most adversely affected. Thus, New England and the Middle Atlantic regions, which historically have had the highest electric rates, also had the highest rates of increase during the last year. By 1974, rates in these regions exceeded the national average by more than 10 mills.

The South Atlantic region also had increases in consumer charges that exceeded the national average, partially because of its use of oil and, more importantly, because of its heavy reliance on the purchase of coal on the spot market. The South Atlantic region relied on the spot market for nearly 40 percent of its coal purchases, while the national average was approximately one-half this amount. Due to the economic pressures resulting

from increased demand and an impending national coal strike, spot prices for coal escalated at an annual rate of 160 percent while long-term contracts for coal increased by only 40 percent.

States along the Pacific coast were hard hit in 1974, due to the combined effects of a reduction in the availability of hydro-electric generation, gas curtailments, and the Arab oil embargo.

Increases Due to Environmental Requirements

The primary focus of this study has been to evaluate the relative impact of environmental requirements upon the electric utility industry in the form of consumer charges. Once again, this impact can be segmented into a fuel and a non-fuel component.

Fuel-switching from high sulfur to low sulfur coal and from high sulfur to low sulfur oil for environmental reasons, coupled with coal-to-oil and coal-to-gas plant conversions primarily for environmental reasons, combined to increase the total fuel bill by 2.5 percent.[1] Thus, in terms of fuel costs, the effect of environmental restrictions was a small factor in explaining the rapid increase in electric bills.

Determining the relative impact of environmental requirements upon the non-fuel component of rate increases is extremely difficult. Utilities do not report these capital expenditures separately. A best estimate of the proportion of non-fuel costs of service incurred for environmental reasons would be 7 to 9 percent.

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[1] *Conversions from oil to coal may require capital expenditures for environmental equipment (for example, precipitators and/or scrubbers); however, these conversions are being implemented on the basis of economic and public policy considerations. Thus, the economic rewards of such conversions in the form of lower fuel costs should not be credited to the environmental movement.*

Thus, the overall increase in 1974 electric revenues and average consumer charges can be summarized as shown in the following table.

	Increase in Electric Revenues (billions of dollars)		Increase in Consumer Charges (mills/kWh)	
	Total Industry	Environmental Reasons	Total Industry	Environmental Reasons
Fuel	$5.30	$0.13	3.5	0.1
Non-Fuel	3.80	0.30	2.5	0.2
Total	9.10	0.43	6.0	0.3
Percent of Total[2]	--	4.7%	--	5.0%

Based on this analysis, environmental requirements on a nationwide basis appear to be responsible for no more than 5 percent of the increase in electric rates during 1974. The impact on a given region or an individual utility system could be significantly greater than this national average. In total, the costs associated with environmental clean-up during 1974 were approximately $430 million.

The impact of pollution control expenditures upon future electric rates will be greater, since the bulk of expenditures required to meet the standards required by the Clean Air and Federal Water Pollution Control Acts will be incurred during the 1975-1985 period. However, the relative impact of these expenditures is expected to remain small. A detailed analysis of the future impact of pollution control expenditures will be provided in a forthcoming TBS report to EPA entitled The Economic Impact of Environmental Regulations on the Electric Utility Industry.

[2] *These percentage differences are due only to rounding.*

Guide to the Report

The remainder of the report consists of four chapters and two appendices.

- Chapter III segments the overall rate increases into the fuel and non-fuel components and estimates the impact of these rate increases by customer type and by geographic region.
- Chapter IV analyzes the increase in the fuel component of rates in terms of cost escalation, contract conditions, fuel-switching, and plant conversions--some of which can be attributed to environmental restrictions.
- Chapter V focuses on increases in non-fuel costs of service and relates these increases to general price inflation, capital market conditions, and pollution control expenditures.
- Chapter VI discusses other issues that affect the amount and timing of rate increases, including regulatory lag and energy conservation.
- Appendix A surveys other recent electric rate studies, describes their methodologies, and briefly compares their findings with those of TBS.
- Appendix B details the investor-owned utilities sampled and describes the information collected from each utility.

III. OVERALL RATE INCREASES

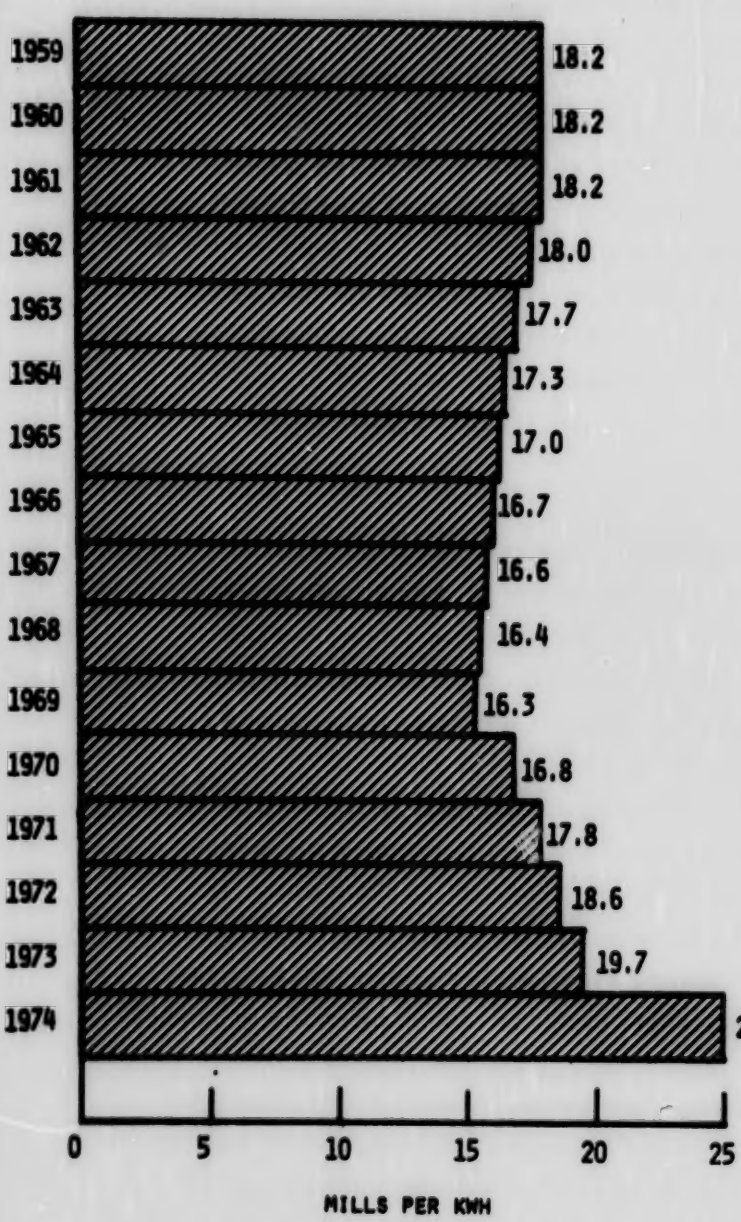
Throughout the 1960s, the cost of electricity declined slowly from 18.2 mills per kilowatt hour in 1959 to 16.3 mills in 1969. This period of declining costs accompanied a growth in the use of electricity in excess of the escalation in the costs of service. During the early 1970s, despite a continued growth in the use of electricity, the costs of electric service increased approximately 5 percent per kilowatt hour per year--to 19.7 mills per kilowatt hour in 1973.

1974 saw a dramatic shift in the cost of electricity. TBS estimates that the increase in average revenues per kilowatt hour was in excess of 30 percent, increasing the average consumer charge by 6.0 mills to 25.7 mills per kilowatt hour. The magnitude of the increases in revenues per kilowatt hour during the 14-year period 1960-1973 was only one-fourth of the increase that occurred in 1974 alone! Exhibit 1 summarizes the level and rates of change in revenues per kilowatt hour since 1960. This sharp increase in consumer charges, coupled with general economic decline and perhaps with some non-price energy conservation efforts, resulted in an almost unprecedented decline in electricity usage.

It is useful to keep the price changes of electricity in perspective with the price changes of competing energy sources. For example, if the fossil fuel cost increases absorbed by the electric utility industry in 1974 were indicative

EXHIBIT 1

REVENUES PER KILOWATT HOUR
1959 - 1974



PERIOD	ANNUAL GROWTH RATE (%) EEI DATA	ANNUAL GROWTH RATE (%) TBS SAMPLE
1960 - 1964	(1.0)	N.A.
1965 - 1969	(1.2)	N.A.
1970 - 1973	4.9	N.A.
1974	-	30.5

N.A. = not available

Source: EEI Statistical Yearbook of the Electric Utility Industry
TBS Sample of Investor-Owned Utility Systems

of the general rate of increases in alternative sources of energy, then electricity increased less than these other energy sources, as the following brief table indicates.

	Percent Increase in 1974
Electricity (¢/kWh)	30.5%
Coal (¢/million Btu)	68.5%
Oil (¢/million Btu)	136.5%
Gas (¢/million Btu)	33.0%

The remainder of this chapter details the relative impacts of the increase in the costs of service by customer type and by geographic region, and then segments these costs by major components--fuel and non-fuel charges.

Rate Increases by Customer Type

Residential, commercial, and industrial customers provided 96 percent of the revenues of investor-owned utilities during 1973 and 1974, with the remaining 4 percent representing street and highway lighting, other public authorities, railroads and railways, and interdepartmental sales.[1] While the distribution of customers serviced by electric utilities has remained relatively stable during the last few years, differences in their respective consumer charges have narrowed as a result of the increasing importance of fuel costs.

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[1] *During 1973, residential customers provided 40.2 percent of operating revenues while commercial and industrial customers totaled 55.8 percent. Preliminary 1974 information indicates that these customer types accounted for 38.8 and 57.2 percent, respectively.*

Differences in consumer charges between classifications of customers and among customers of different sizes within a customer classification have recently become areas of concern for some public policy-makers, especially those who believe in using the price mechanism for income distribution and/or energy conservation. The differential in average costs between customer classifications theoretically represents the differences in their respective costs of service. Large industrial users, who have the lowest average charges, tend to require less fixed capital per kilowatt hour consumed than the small residential user. Within a customer classification, the larger user theoretically is able to spread his fixed costs across more kilowatt hours and thereby lower the fixed burden per kilowatt hour.

Utilities have attempted to capture these characteristics of burden absorption in their rates by utilizing different rate structures for different customer classifications and by utilizing a declining block structure within each customer class. Therefore, the larger a customer's use, the lower his average charge per kilowatt hour.[2]

Historically, the average charge for commercial and industrial customers has been less than two-thirds that for residential customers. However, the recent escalation in fossil fuel costs, which are generally allocated to each customer on a kilowatt hour basis through a fuel adjustment

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[2] *In addition, large industrial users tend to have better load factors. Thus, operating characteristics, as well as size, are a contributing factor to the lower rates of large industrial users.*

clause, has narrowed this relative differential. In 1974 the average commercial and industrial charge was 72 percent of the average residential charge.

Exhibit 2 summarizes the recent trends in rates by customer type. While the average consumer charge was increasing by 30.5 percent in 1974, the average charge for residential customers increased by only 23.2 percent compared to the 33.1 percent increase for commercial and industrial customers. Thus, one could conclude that recent trends in utility rates are not regressive across customer classifications.[3] It should be noted, however, that the absolute difference in rate levels between residential customers and commercial and industrial customers has been increasing--from 8.3 mills per kilowatt hour in 1972 to 8.8 mills per kilowatt hour in 1974.

The rapid escalation in electric bills during 1974 has evoked considerable concern over the equity of current rate structures. Some advocates contend that electricity is a homogeneous product and that all customers should be charged the same rate per kilowatt hour, irrespective of usage. Others argue that rates should be cost-justified and, therefore, should reflect the added costs incurred to service customers during periods of peak usage . Partially as a result of these divergent views, the Federal Energy Administrations's Office of Energy Conservation and Environment (among others) has undertaken a series of studies to determine the appropriate public policy. This program includes rate structure and metering experiments which will not be completed for several years.[4]

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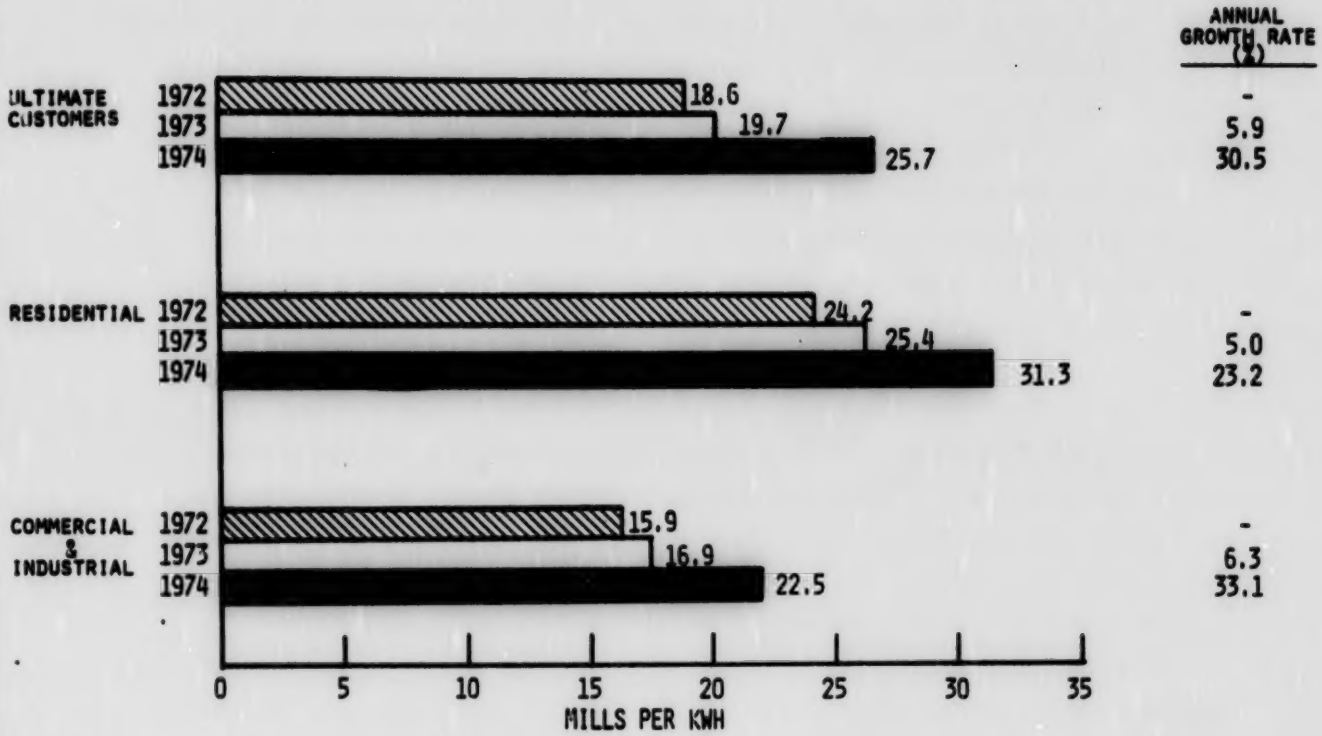
[3] *In addition, recent trends in the formulation of rate levels within customer classes have also been progressive.*

[4] *TBS is nearing completion of the initial study in this FEA program entitled A Study of Electric Utility Industry Costs, Demand, and Rates.*

EXHIBIT 2

REVENUES PER KILOWATT HOUR BY TYPE OF CUSTOMER
ULTIMATE CUSTOMERS, RESIDENTIAL, AND COMMERCIAL & INDUSTRIAL

1972 - 1974



Source: EEI Statistical Yearbook of the Electric Utility Industry
TBS Sample of Investor-Owned Utility Systems

Rate Increases by Geographic Region

Significant regional differences in average consumer charges have existed for many years. The recent escalation in the costs of electric service has in some ways magnified this regional problem. Exhibit 3 summarizes the recent trends in rates by geographic region. Exhibit 4 details the geographic regions defined by the Bureau of Census and used by Edison Electric Institute, among others.

Historically, New England and the Middle Atlantic census divisions have had the highest electric rates in the country. In 1973, these regions had average consumer charges of 26.4 and 25.6 mills per kilowatt hour, respectively--approximately 20 percent higher than the next closest region, the West North Central region. The other regions had average rates ranging from 15.2 to 19.0 mills per kilowatt hour, with the lowest rates in the South Central regions, both East and West, followed by the Western regions (Mountain and Pacific), and the other Eastern regions (South Atlantic and East North Central).

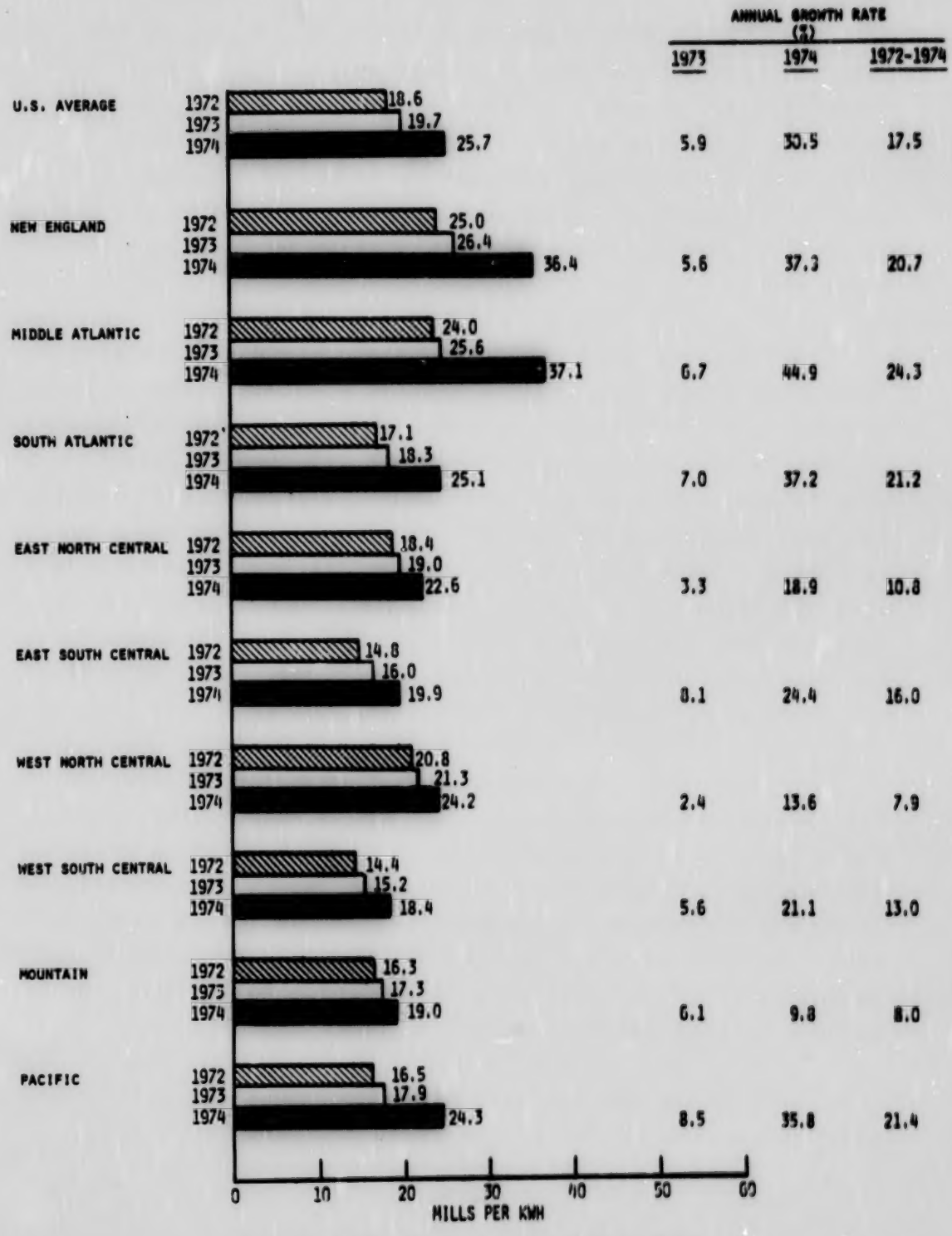
In 1974 these regional variations were exacerbated, although not uniformly. The hardest-hit regions were those along both coasts of the United States. These regions (New England, Middle Atlantic, South Atlantic, and Pacific) faced rate increases in excess of 35 percent during the year. In contrast, the Central and Mountain regions incurred increases of less than 25 percent. Nationwide, the average rate of increase was 30.5 percent.

During the two-year period encompassing 1973 and 1974, these coastal regions averaged increases in excess

EXHIBIT 3

REVENUES PER KILOWATT HOUR BY GEOGRAPHIC REGION

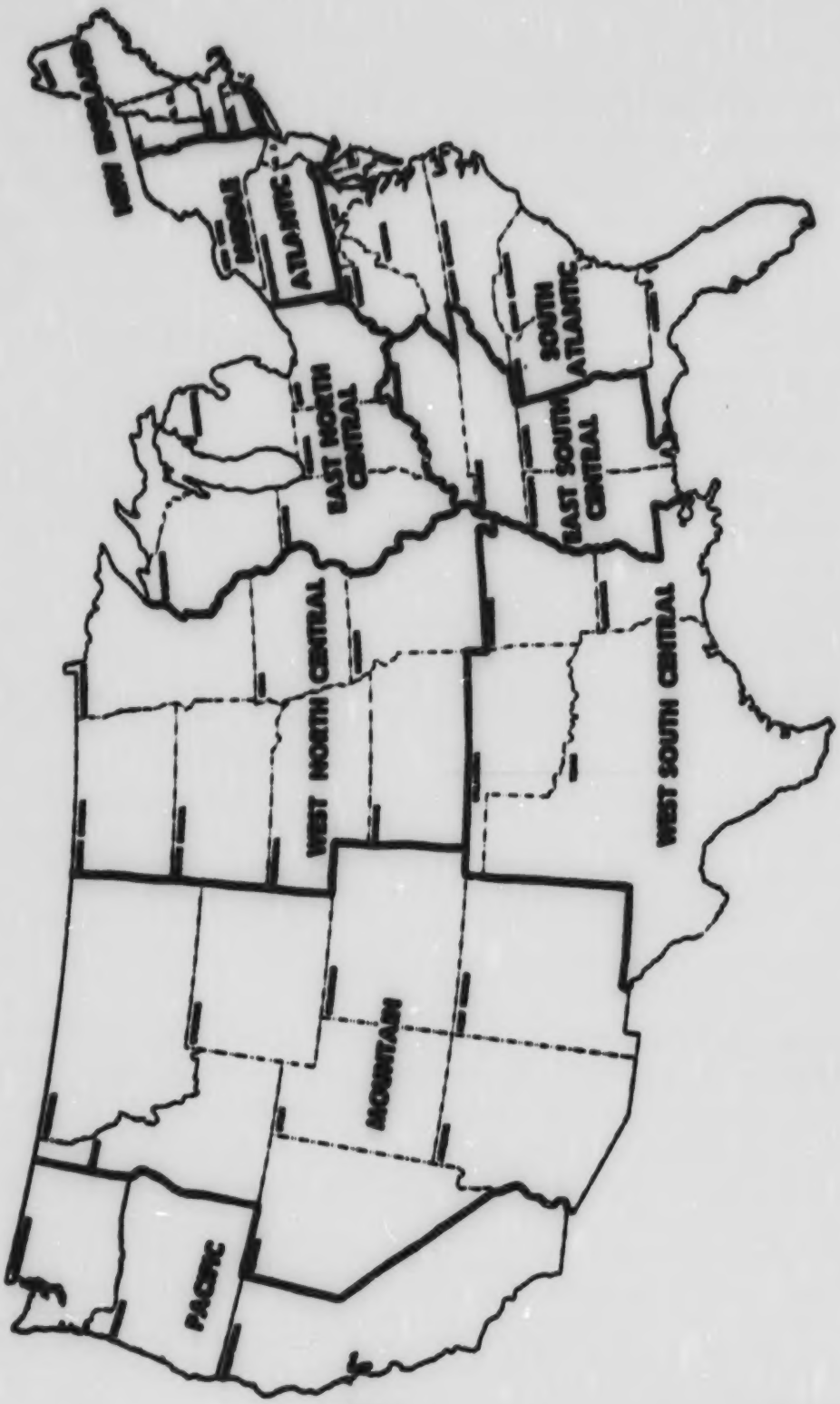
1972-1974



Source: EEI Statistical Yearbook of the Electric Utility Industry
TBS Sample of Investor-Owned Utility Systems

Exhibit 4

BUREAU OF CENSUS GEOGRAPHIC REGIONS



of 20 percent per year, while the South Central regions increased approximately 15 percent per year and the remaining regions averaged less than 11 percent. The annual increase on a nationwide basis was 17.5 percent for this two-year period.

The coastal regions that exhibited the highest rate increases were also those regions that depended heavily upon oil, either as their dominant fossil fuel or as a replacement for natural gas, which has been in short supply. The rapid escalation in oil costs relative to other fossil fuels was the dominant regional factor during the last two years.

Rate Increases by Major Cost Component

From a regulatory perspective, rate increases can be segmented into those which result from general rate increases and those which are passed through to the consumer in the form, for example, of a fuel adjustment clause. While this division follows from the regulatory procedures employed, it is not necessarily the most useful for analysis.[5]

When evaluating the factors underlying recent rate increases, a useful dichotomy can be made between fuel- and non-fuel-related increases. This differs from the general rate increase and the fuel adjustment categories used in rate proceedings since the general rate usually includes a

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[5] *For example, the analysis of fuel adjustment clauses recently undertaken by the Congressional Research Service, Library of Congress, significantly overstated the relative increase due to increased fuel costs. See Appendix A for an evaluation of this study.*

basic fuel charge--for example, 30 cents per million Btu. Deviations in fuel costs from this base level are then incorporated, usually with a time lag, into the fuel adjustment clause.

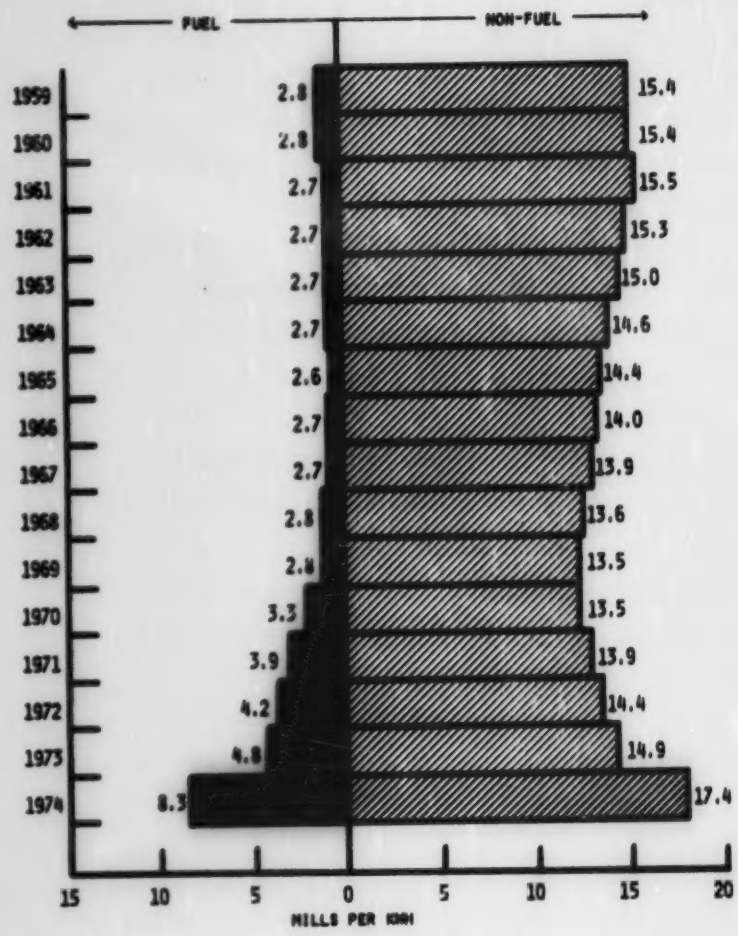
Using the fuel and non-fuel categories, recent trends in these major components are summarized in Exhibit 5. In the fuel component, the 1960s began and ended with the same basic charge of 2.8 mills per kilowatt hour. During the same period, the non-fuel charges declined steadily from 15.4 mills per kilowatt hour in 1960 to 13.5 mills in 1969, an annual decline slightly in excess of 1 percent. Thus, although net fuel costs remained constant on a kilowatt hour basis, the proportion of the average consumer charge allocated to the fuel component increased from 15 percent to approximately 20 percent during the 1960s.

The early 1970s saw both of these trends change. First, the charges associated with fuel began to increase nearly 15 percent per year. Second, after one stable year, the non-fuel charges began to increase at an average growth rate of 2.5 percent. In total, the average consumer charges increased nearly 5 percent per year during this period. Given the more rapid rate of growth in the fuel component, the proportion of overall consumer charges allocated to fuel increased from less than 20 percent to nearly one-fourth of the total.

During 1974, the rapid fuel cost escalation resulted in fuel constituting nearly one-third of the average consumer charge. The fuel charge increased from 4.8 mills per kilowatt hour in 1973 to 8.3 mills in 1974, an increase of more than 70 percent during the year. At the same time,

EXHIBIT 5

REVENUES PER KILOWATT HOUR BY MAJOR COST COMPONENT
1959 - 1974



PERIOD	ANNUAL GROWTH RATE (%)	
	% INCREASE FUEL	% INCREASE NON-FUEL
1960 - 1964	-0.7	-1.1
1965 - 1969	+0.7	-1.6
1970 - 1973	+14.4	+2.5
1974	+72.9	+16.8

Source: EEI Statistical Yearbook of the Electric Utility Industry
TBS Sample of Investor-Owned Utility Systems

non-fuel charges posted their largest annual increase, going from 14.9 to 17.4 mills per kilowatt hour--an increase of nearly 17 percent. Overall, the rate increase was 30.5 percent.

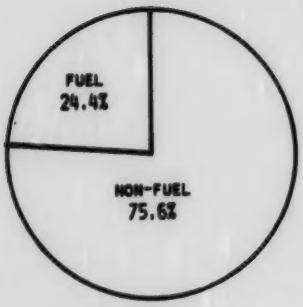
Thus, average revenues per kilowatt hour increased by 6.0 mills during 1974. Increases in fuel costs accounted for 3.5 mills, or 58.3 percent, of this total. The remaining 2.5 mills (41.7 percent) reflected increases due to general price inflation, capital charges, and miscellaneous costs of service. Exhibit 6 summarizes the relative contribution of these cost components.

The next two chapters of this report detail the analysis of these major cost components and attempt to segment the 1974 rate increase into that proportion which is linked to environmental issues and that which follows from other economic considerations.

EXHIBIT 6

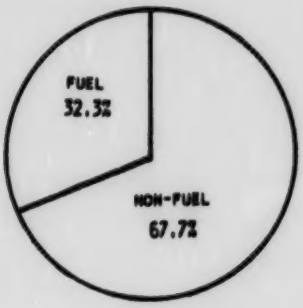
REVENUES PER KILOWATT HOUR BY MAJOR COST COMPONENT
PERCENTAGE BREAKDOWN

1973-1974



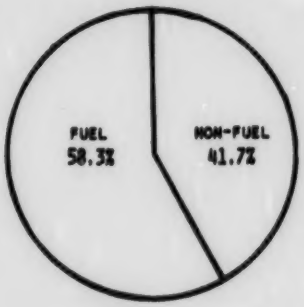
1973

PERCENTAGE BREAKDOWN
OF REVENUES PER KILOWATT HOUR



1974

PERCENTAGE BREAKDOWN
OF REVENUES PER KILOWATT HOUR



1973-1974

PERCENTAGE BREAKDOWN
OF CHANGES IN REVENUES PER KILOWATT HOUR

Source: EEI Statistical Yearbook of the Electric Utility Industry
1973 Edition of Investor-Owned Utility Systems

IV. INCREASES IN THE FUEL COMPONENT OF RATES

There are at least six reasons underlying the rapid escalation in fuel charges during 1974:

(1) fossil fuel cost escalation by itself;

(2) changes in contract conditions for fossil fuels;

(3) fuel-switching from high sulfur to low sulfur coal and/or high sulfur to low sulfur oil;

(4) coal-to-oil and/or coal-to-gas conversions, primarily for environmental reasons;

(5) oil-to-coal and/or oil-to-gas conversions for reasons of availability, price, or conservation of scarce fossil fuels; and

(6) natural gas curtailments resulting in gas-to-coal and/or gas-to-oil conversions.

In discussing the impact of higher fuel costs, consideration must be given to nationwide shifts in generation mix toward nuclear and away from fossil fuels, as well as regional differences emanating from differing generation mixes from fossil fuels.

Of the remaining reasons, only the third and the fourth have been attributed to environmental reasons within this report,[1] and care has been taken to segment these

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[1] *This report focuses upon the impact of environmental regulations since 1973. Thus, increased fuel costs and/or pollution control expenditures prior to 1973 have not been isolated and, in this sense, the impact of environmental regulations will be understated.*

factors from the general escalation of fossil fuel costs and the compensating changes in generation mix. While conversions from oil to coal may require capital expenditures for environmental equipment (e.g., precipitators and/or scrubbers), these conversions are being implemented on the basis of economic and public policy considerations. Thus, the economic rewards of such conversions in the form of lower fuel costs should not be credited against the increased capital charges associated with the above-mentioned pollution control equipment.[2] Gas curtailments have been assumed to be for reasons other than environmental.

Fuel Cost Escalation

While many industry observers have forecast that nuclear generation will represent a significant proportion of future generation, the electric utility industry has historically depended upon fossil-fueled conventional steam-electric plants for the bulk of its generation. During 1972, fossil-fueled steam generation accounted for more than 90 percent of all investor-owned generation. By 1974, the expansion of nuclear generation and the change in the relative economics of alternative sources of generation reduced this dependence to less than 87 percent of generation. Although these trends in generation somewhat reduce the dependence upon fossil fuels, the costs of alternative fossil fuel sources remain extremely important in the fuel component of rate increases.

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[2] *Unfortunately, the increased operating costs associated with these environmental requirements (e.g., handling costs, sludge removal, etc.) cannot be isolated.*

Needless to say, all fossil fuels exhibited dramatic increases in costs during the 1973-1974 period. These cost trends are summarized in Exhibit 7 for each fossil fuel and for a weighted composite of all fossil fuels.[3] The initial impact of the Arab oil embargo is reflected in the fuel cost increases during 1973. In that year, a composite of fossil fuels increased in cost nearly 18 percent, with oil dominating with a 26 percent increase, followed by gas with a 13 percent and coal with a 9 percent increase.

These fuel cost increases pale when compared to those which occurred during 1974. Overall, the composite cost of fossil fuels for electric generation increased from 48.4 to 90.1 cents per million Btu, an 86 percent increase. Once again the increase in the cost of fuel oil dominated with an increase of 136.5 percent. The cost of coal also escalated rapidly, increasing by 68.5 percent during the year. This significant increase in the price of coal can be attributed primarily to increased demand for coal due to the rapid escalation in the price of oil. But hedging in anticipation of a long coal strike doubtless was also a major factor. Despite the dwindling supply of natural gas, the regulation of interstate gas prices by the Federal Power Commission held the cost increase of this clean fuel down to 33 percent.

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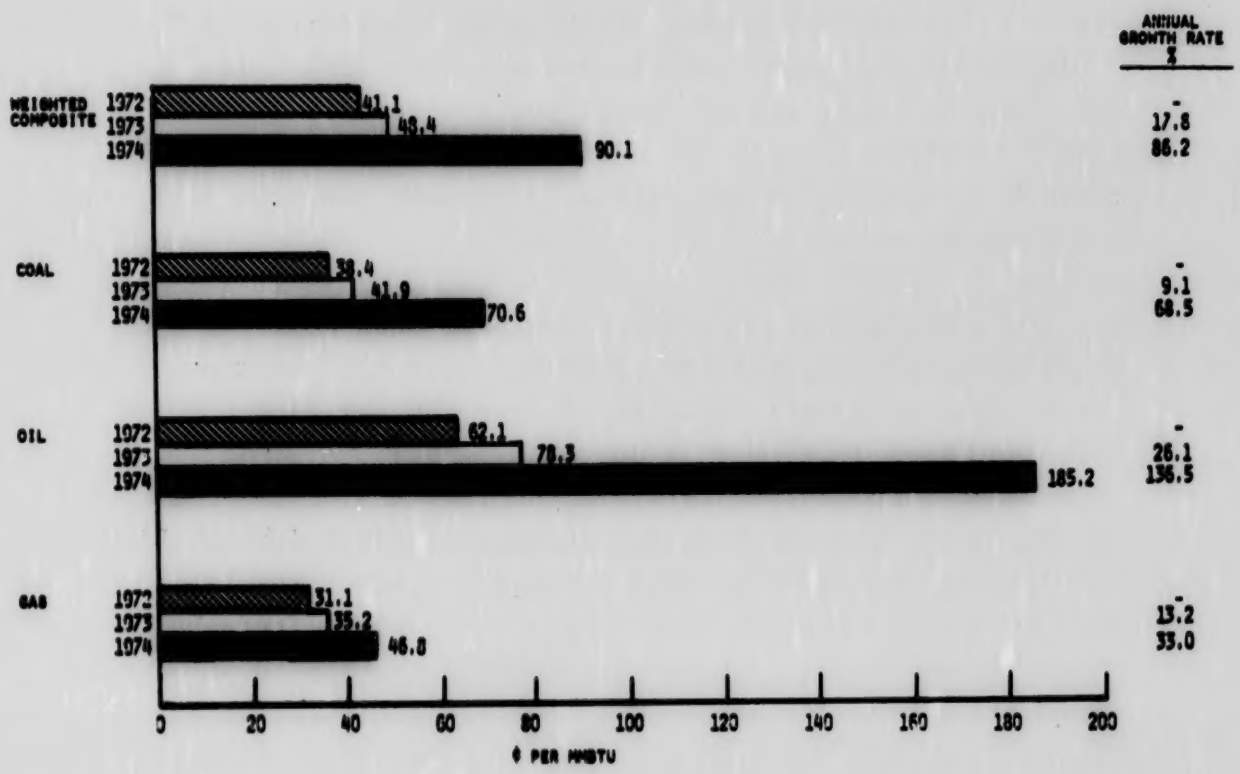
[3] *The composite represents an average fuel cost weighted by the percent generation from each fossil fuel.*

EXHIBIT 7

FOSSIL FUEL COSTS BY TYPE OF FUEL

1972 - 1974



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CHANGES IN GENERATION MIX

The above-mentioned increases in fossil fuel costs were mitigated somewhat by a shift in generation mix, both away from fossil fuels in general and toward less expensive fossil fuels where available. Exhibit 8 details the generation by prime mover. During the last two years, generation from nuclear fuel has increased from 50 billion to nearly 100 billion kilowatt hours, and has increased from 3.7 to 6.8 percent of total generation. With hydro-electric generation remaining relatively constant, this increase in nuclear generation permitted a reduction in generation from more expensive fossil fuels.

Recent trends in generation among fossil fuels are summarized in Exhibit 9. Generation from coal has increased during the last two years, reversing the historic trend away from coal. This increase in coal utilization has permitted a reduction in generation from oil and gas, a shift based on relative costs and/or availability. The magnitude of these changes will be discussed further in relation to fuel-switching conversions for economic and environmental reasons.

FUEL COSTS BY REGION

The significant difference in overall rate increases on a regional basis can be traced to regional differences in composite fuel costs. The census divisions that include the coastal states, both Atlantic and Pacific coasts, have historically had higher fuel costs

EXHIBIT 8

GENERATION BY PRIME MOVER
PERCENTAGE BREAKDOWN
1972 AND 1974

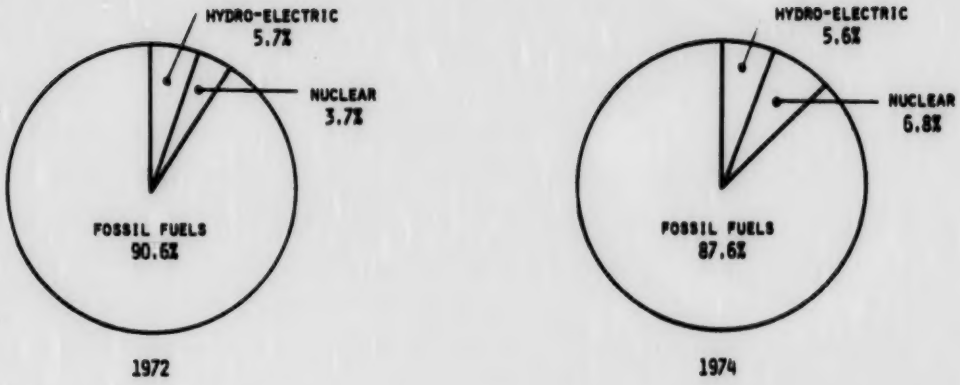


EXHIBIT 9

FOSSIL FUEL GENERATION BY TYPE OF FUEL
PERCENTAGE BREAKDOWN

1972 AND 1974

Source: EEI Statistical Yearbook of the Electric Utility Industry
The Sample of Investor-Owned Utility Systems

per million Btu. These same coastal areas were the only regions where overall rate increases were in excess of the national average during this period. Exhibit 10 summarizes recent regional trends in composite fossil fuel costs.

The hardest hit region during 1973 was the Pacific census division, a result of a reduction in hydro-electric generation, gas curtailments, and the Arab oil embargo. During 1974, the regions most severely affected were those located along the Atlantic coast. Composite fuel prices more than tripled in New England and more than doubled in the Middle and South Atlantic regions. All other regions had composite fuel increases very near or below the national average of 86 percent during 1974 and the annual average of 48 percent during the 1973-1974 period.

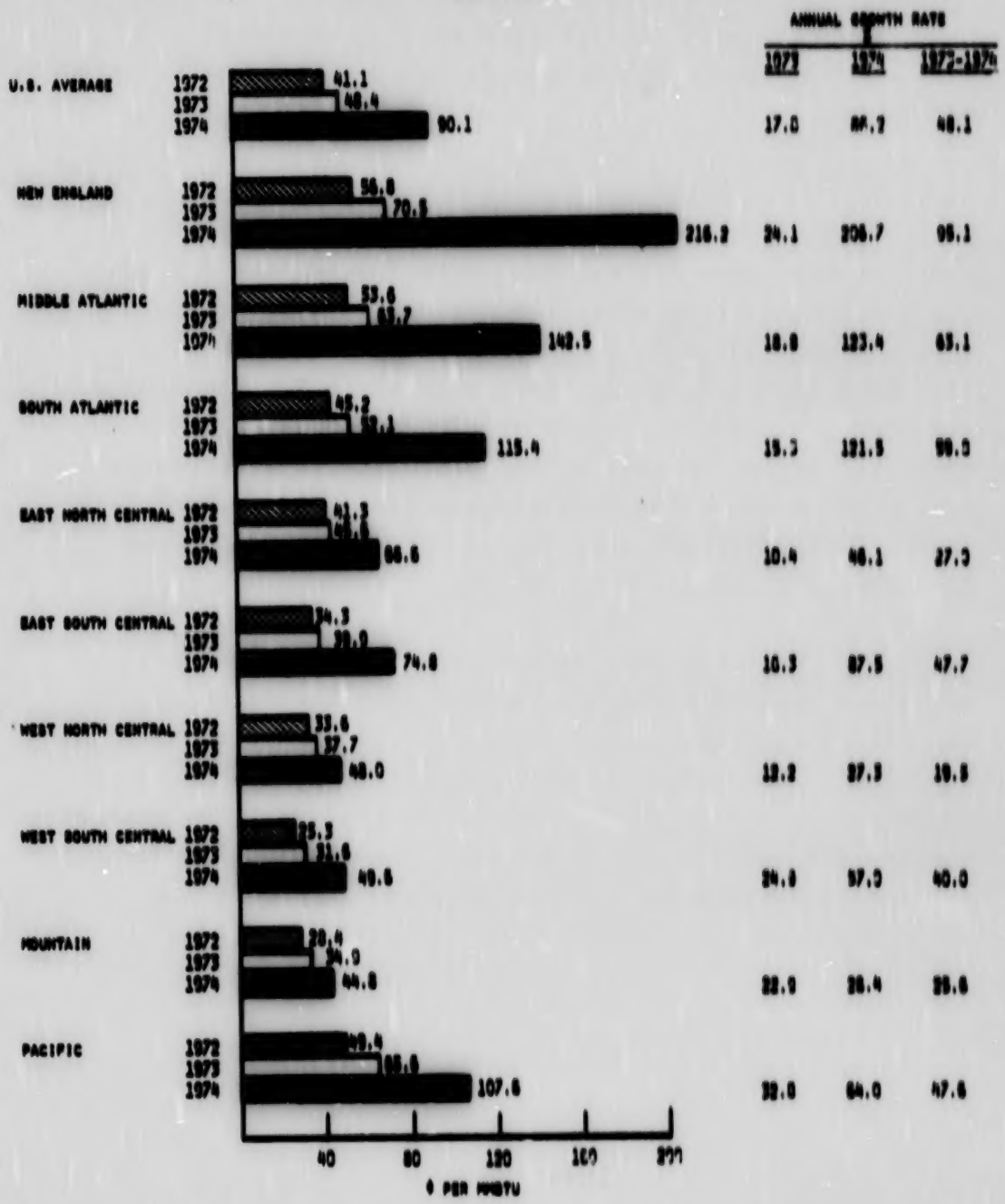
These regional differences in composite fuel costs are primarily due to a significant variation in the mix of generation from fossil fuels. Exhibits 11 and 12 provide a regional summary of fossil fuel mix, segmented into high and low oil-using regions. The coastal regions all utilize oil in excess of the national average, reflecting their accessibility to ocean transport and, until the Arab oil embargo, cheap residual fuel oil.

EXHIBIT 10

COMPOSITE FOSSIL FUEL COSTS BY GEOGRAPHIC REGION

WEIGHTED AVERAGE OF COAL, OIL AND GAS

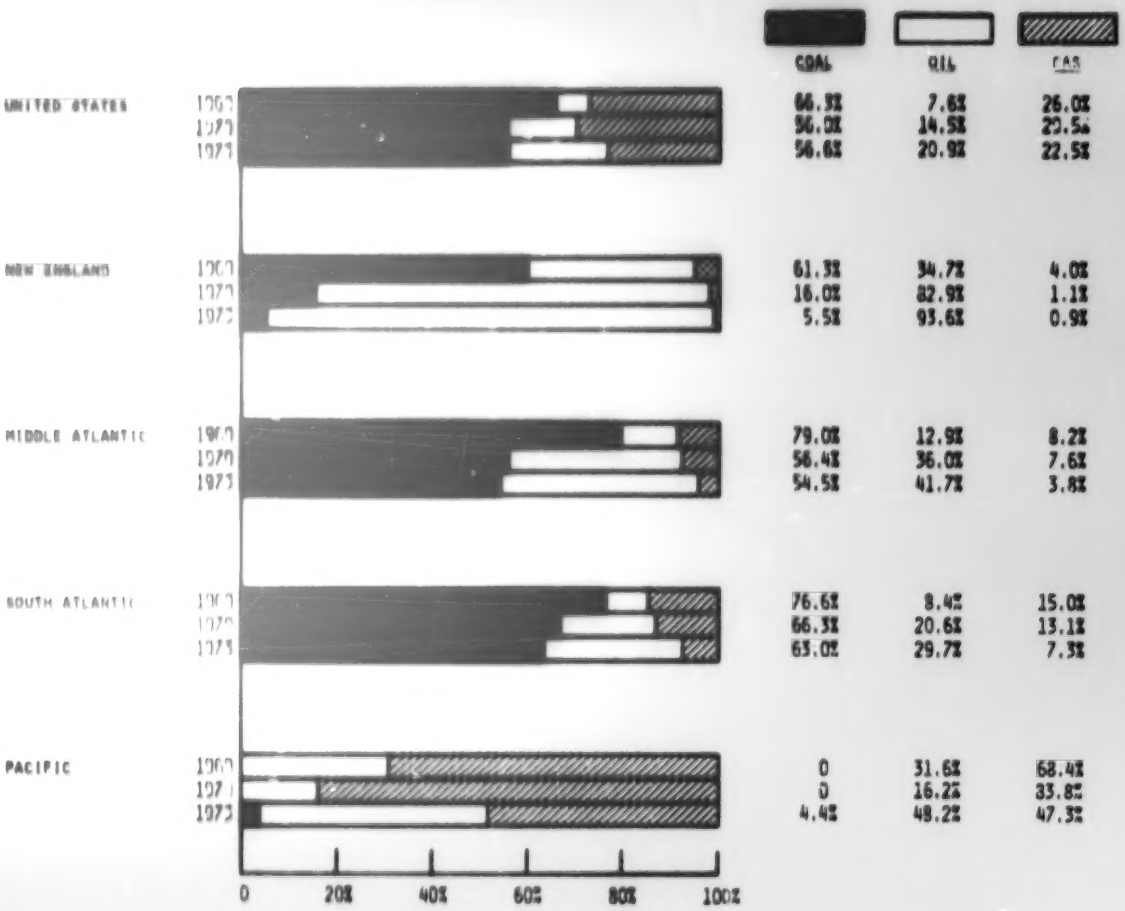
1972-1974



Source: EEI Statistical Yearbook of the Electric Utility Industry
THE COSTS OF INTERMEDIATE-SERVICE UTILITY SYSTEMS

EXHIBIT 11

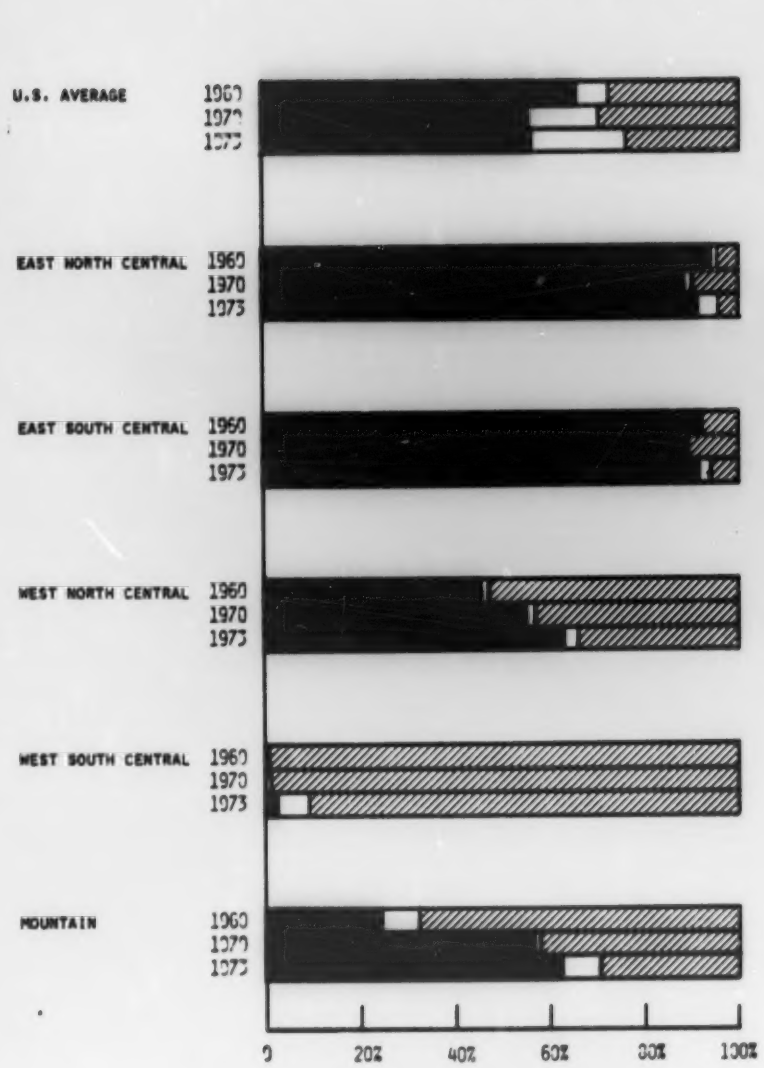
KILOWATT HOURS GENERATED BY COAL, OIL, AND GAS
PERCENTAGE BREAKDOWN
HIGH OIL-USING REGIONS
1960, 1970 AND 1973



Source: [1] Statistical Yearbook of the Electric Utility Industry

EXHIBIT 12

KILOWATT HOURS GENERATED BY COAL, OIL AND GAS
PERCENTAGE BREAKDOWN
LOW OIL - USING REGIONS
1960, 1970 AND 1973



		COAL	OIL	GAS
U.S. AVERAGE	1960	66.3%	7.6%	26.0%
	1970	56.0%	14.5%	29.5%
	1973	56.6%	20.9%	22.5%
EAST NORTH CENTRAL	1960	96.1%	0.4%	3.5%
	1970	89.3%	2.3%	8.4%
	1973	92.0%	4.5%	3.4%
EAST SOUTH CENTRAL	1960	93.1%	0.1%	6.8%
	1970	89.6%	0.2%	10.2%
	1973	92.9%	2.3%	4.7%
WEST NORTH CENTRAL	1960	46.2%	2.0%	51.8%
	1970	56.4%	1.8%	41.8%
	1973	64.1%	2.2%	33.7%
WEST SOUTH CENTRAL	1960	0	0.2%	99.8%
	1970	0	0.4%	99.6%
	1973	3.2%	5.9%	90.9%
MOUNTAIN	1960	24.4%	8.3%	67.3%
	1970	57.5%	2.7%	39.8%
	1973	62.7%	7.7%	29.6%

Source: EEI Statistical Yearbook of the Electric Utility Industry

Changes in Contract Conditions

Before discussing in full the impact of fuel-switching in terms of sulfur content and plant conversions, it should be noted that any cogent analysis of recent trends should take into account the chaotic market conditions that have prevailed since the imposition of the Arab oil embargo in late 1973 and the subsequent institution of petroleum allocation regulations on 15 January 1974. Although these regulations dealt only with crude oil, refined products, and residual fuel oil, their impact on competitive fuels was significant.

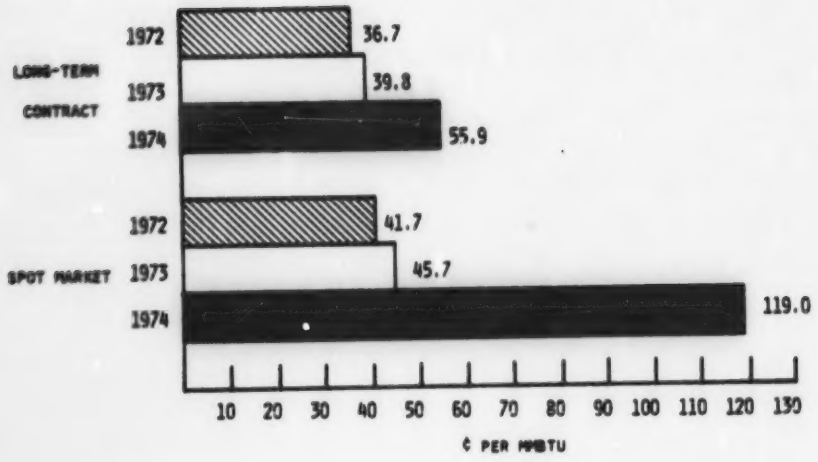
For example, the spread between long-term and spot contract prices for coal was 5 to 6 cents per million Btu in 1972 and 1973. In 1974, however, the difference between long-term and spot contracts jumped to nearly 65 cents per million Btu, and the spot price was more than twice the long-term price--55.9 cents per million Btu for coal purchased on long-term contracts versus 119.0 cents per million Btu on the spot market. These trends in coal prices are summarized in Exhibit 13.

The increases in coal prices represent a 40 percent increase in the long-term price and more than a 160 percent increase in the spot market price. These wide differences in the cost of coal could reflect both the sudden increase in the demand for coal due to higher oil prices and the hedging which preceded the nationwide coal strike. By the end of the year, with the threat of a long coal strike ended, the spread between the spot and long-term prices of coal narrowed somewhat. Surprisingly,

EXHIBIT 13

COAL COSTS BY TYPE OF CONTRACT

1972-1974



Source: Federal Power Commission Form 423
TBS Sample of Investor-Owned Utility Systems

however, the percent of coal purchased on the spot market remained steady throughout the 1972-1974 period, at 22 percent of total coal purchases.

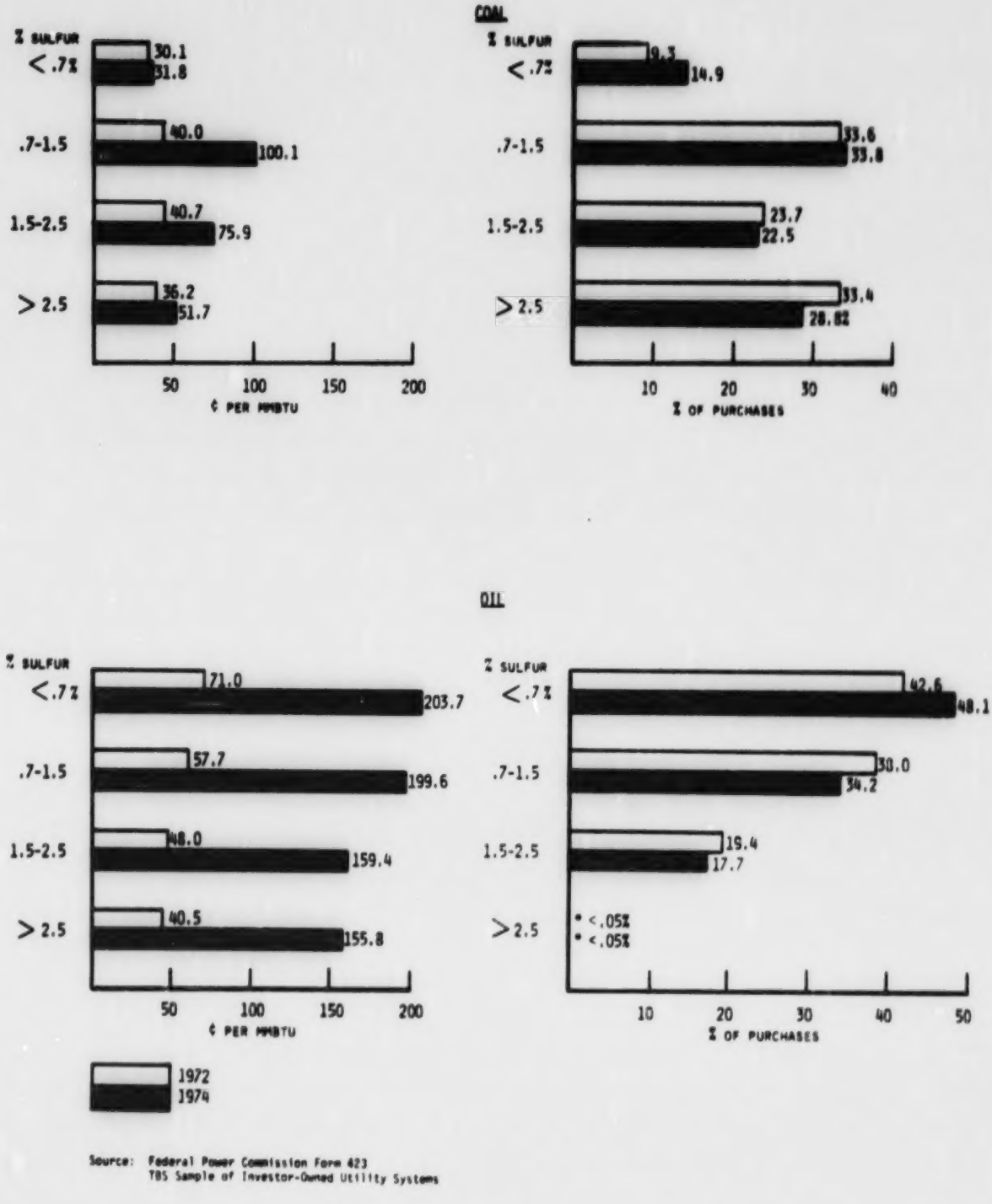
Fuel-Switching: Sulfur Content

Exhibit 14 summarizes recent trends in the relative price and mix of sulfur-laden fuels (coal and oil) by four classifications of sulfur content. Overall, the average cost of coal per million Btu nearly doubled during the 1972-1974 period, accompanied by a decline in the average sulfur content from 1.98 to 1.82 percent. Likewise, oil more than tripled in price, with a reduction in the average sulfur content from 0.96 to 0.92 percent. In both cases, the reduction in sulfur content during 1973 exceeded that in 1974.

Care must be taken in interpreting price movements within a sulfur class. For example, low sulfur coal has been significantly less expensive than high sulfur coal--an apparent statistical anomaly. However, this relationship holds because the "less than 0.7 percent" sulfur coal was low sulfur, low Btu coal delivered to the Mountain and Pacific regions and the "greater than 2.5 percent" coal represented high sulfur Eastern coal delivered primarily to the East North Central region. Moreover, the Western low sulfur coal was all purchased on long-term contracts, and the Eastern high sulfur coal represented some purchases of spot coal, approximately 15 percent. In addition, "0.7 - 1.5 percent" coal, which

EXHIBIT 14

COAL/OIL COSTS AND PURCHASES
BY SULFUR CONTENT
1972 AND 1974



Source: Federal Power Commission Form 423
TBS Sample of Investor-Owned Utility Systems

had the highest rate of increase in price, was predominantly purchased in the South Atlantic region, where the proportion of spot purchases has been nearly twice the national average. Thus, relative price effects of coal purchases were dominated by regional and contract issues, and not necessarily by fuel availability or sulfur content. Comparable anomalies did not exist among the sulfur classes for oil.

Perhaps the best way to segment the relative effect of price escalation from the impact of lower sulfur content required for environmental reasons is to undertake a variance analysis for each sulfur-laden fuel. The data for such analyses have already been summarized in Exhibit 14.

The composite cost for coal and oil in any given year can be determined by summing the product of the average cost in each sulfur class by the corresponding proportion of total purchases represented by that sulfur class. Thus, the weighted average cost for coal was 38.4 cents per million Btu in 1972 and 70.6 cents per million Btu in 1974. These same data can also be employed to determine the "price" effect and the "sulfur" effect. For example, the weighted average cost for 1972 could be compared with the weighted average cost computed using the 1972 mix of fuel by sulfur class and the 1974 prices for these same sulfur classes. Such a computation would yield a "price" effect, holding <u>constant</u> the mix by sulfur content. Likewise, the 1972 weighted average cost could be compared to the weighted average cost computed using 1972 prices and 1974 mix of fuel by sulfur class. This

computation would correspond to the "sulfur" effect, holding constant the price of a fuel by sulfur content.

These computations have been performed and are summarized in the following brief table.[4]

	Coal	Oil
1972 cost (¢/million Btu)	38.0¢	61.5¢
+ "Price" effect	33.8	132.0
+ "Sulfur" effect	(0.4)	0.9
1974 cost (¢/million Btu)	70.5¢	194.5¢

Thus, the impact of fuel-switching in the form of lower sulfur fuel for environmental reasons at the national level amounted to approximately 1 cent per million Btu for oil and was actually negative for coal.[5]

Based upon this analysis, one could conclude that effectively all of the cost increase in fossil fuels during the 1972-1974 period should be attributed to fuel cost escalation, not to increases in environmental requirements to burn low sulfur fuels.[6] Such a conclusion rests

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[4] *In addition, there is a small, second-order, "interaction" effect. Thus, the 1974 cost will approximate, but not be exactly equal to, the 1972 cost plus the "price" effect plus the "sulfur" effect.*

[5] *This apparent anomaly for coal is again linked to the relative increase in the burning of low cost, low sulfur, low Btu Western coal.*

[6] *This conclusion also follows directly from the fact that the weighted average sulfur content of both coal and oil declined only marginally during the last two years.*

upon the use of nationwide averages during the last two years and could understate the actual impact of environmental standards in at least two ways.

First, the requirement to burn a lower sulfur fuel might well have preceded the 1972-1974 time period selected for analysis. If this were true, one could not necessarily attribute the rapid 1974 cost escalation directly to the requirement to burn a lower sulfur fuel.

Second, individual plants could have been required to shift the sulfur content of their fuel and, thus, might have incurred a sulfur "penalty"--i.e., a higher cost fuel with a lower sulfur content. Of the 264 plants included within the TBS sample of investor-owned utilities, those which exhibited a shift in the sulfur content of their fuels from one sulfur classification to another numbered less than 15 percent of the total. Surprisingly, nearly as many plants exhibited an increase in sulfur content, as did those which decreased the sulfur content of their fuel (16 plants versus 20 plants).

In order to estimate the cost impact associated with this so-called sulfur "penalty," a plant-by-plant analysis of these added fuel costs was undertaken. Assuming that each plant which burned a lower sulfur fuel in 1974 than 1972 did so for environmental reasons and that the sulfur restrictions impacted all generating units within that plant, the additional fuel costs directly associated with the burning of lower sulfur content fuels amounted

to 2.4 percent of total fuel costs.[7] On the other hand, those plants which burned a higher sulfur content fuel in 1974 realized a cost savings of 1.0 percent. Thus, the net effect of a shift toward lower sulfur fuels in 1974 amounted to 1.4 percent of total fuel costs, equally distributed between coal and oil.

The sulfur penalty for coal cannot easily be computed due to the previously referenced regional and contract issues. However, the sulfur penalty for oil has increased in absolute terms, but also has declined in relative terms. That is, the cost difference between "less than 0.7 percent" and "greater than 2.5 percent" oil has increased from approximately 30 cents per million Btu in 1972 to nearly 50 cents per million Btu in 1974. At the same time, the relative surcharge for low sulfur oil has declined from approximately 75 percent (i.e., 30.5¢/million Btu + 40.5¢/million Btu) to less than 31 percent (i.e., 47.5¢/million Btu + 155.8¢/million Btu).

FUEL-SWITCHING: PLANT CONVERSIONS

While some utilities have responded to environmental requirements and economic conditions by continuing to burn a given fuel but switching its sulfur content,

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[7] *This analysis does not credit to environmental reasons the apparent cost savings realized when a utility shifts from "greater than 0.7 percent" sulfur coal to "less than 0.7 percent," since this effect is primarily based upon regional and/or contractual differences.*

other utilities have converted generation units from one fossil fuel to another. For example, some plants have been converted from coal to other fossil fuels in order to meet environmental standards. Other plants have been converted from oil to other fossil fuels for reasons of fuel availability, relative price, or conservation of petroleum. Finally, natural gas curtailments have resulted in conversions from gas to more expensive fuels.

Of these plant conversions, only those which represent a conversion from coal to other fossil fuels have been assumed to have been undertaken for environmental reasons. The others were assumed to have resulted from economic or public policy considerations.

In determining the economic impact associated with each of these categories of conversion, it was arbitrarily assumed that a shift in generation of more than 10 percent from any given plant represented a "conversion." Shifts in generation mix of less than 10 percent were assumed to represent shifts in generation dispatch without the physical conversion of a given unit from one fossil fuel to another.

COAL-TO-OIL AND COAL-TO-GAS CONVERSIONS

Of the 264 plants within the TBS sample, only 3 percent had converted from coal to either oil or gas during 1973 or 1974. These conversions, which were assumed to have occurred because of environmental restrictions, resulted in an increase in fuel costs in the case of conversions to oil and a decrease in the case of conversions to natural gas. In

addition, there most likely were additional non-fuel operating expenses, some of which may have been capitalized.

The net effect of these conversions was to increase the total fuel costs incurred during 1974 by approximately 1 percent.

OIL-TO-COAL AND OIL-TO-GAS CONVERSIONS

Fuel shifts away from oil were clearly the result of economic considerations, instructions from the Federal Energy Administration, or the relaxation of environmental requirements. In any case, the net effect was a reduction in the overall fuel costs since oil was by far the most expensive fossil fuel.

During the 1972 to 1974 period, 6 percent of the plants within the nationwide sample reduced their steam-electric generation from oil by more than 10 percent. This conversion decreased total fuel charges by 2 percent during 1974. This cost savings could have been restricted somewhat by the requirement to burn a low sulfur fuel in the case of coal.

GAS-TO-COAL AND GAS-TO-OIL CONVERSIONS

During the last two years, natural gas curtailments have had a significant impact upon the electric utility industry. Cutbacks in the availability of natural gas as boiler fuel adversely impacted nearly 20 percent of the plants included in the TBS sample. These plants were required to substitute either coal or oil. In most cases

the fuel selected was oil due to the boiler design. In some cases the choice of fuels might have been based upon environmental considerations.

These natural gas curtailments increased fuel costs by approximately 6.5 percent during 1974.[8]

SUMMARY

Fuel costs were by far the most important component in the dramatic increase in electric rates during 1974. While overall rates increased by 30.5 percent, the costs associated with fuel increased by 72.9 percent. Thus, the 86.2 percent increase in the composite cost of fossil fuels was somewhat offset both by the lower rates of cost escalation for nuclear and hydro-electric generation and by the shift in the mix of generation toward nuclear and hydro-electric sources. In addition, generation from fossil fuels shifted toward coal for reasons of cost and availability.

By far the single most important reason for the increase in fuel costs was price escalation, particularly for oil. The rapid increase in oil prices followed the Arab oil embargo. Shifts in the cost and short-run availability of this fossil fuel impacted the price of competing fossil fuels. In addition, the upward pressure on the fuel prices was exacerbated by both the fear of a prolonged coal strike and the availability of natural gas.

---

[8] *It should be noted that this increase might have been less without restrictions on the sulfur content of other fossil fuels.*

In attempting to estimate the impact of environmental regulations upon the fuel component of electric bills, fuel-switching from high to low sulfur coal and/or oil and from coal to oil and/or gas was isolated. These two factors combined to increase the total fuel bill by 2.5 percent--1.4 percent attributed to burning lower sulfur fuels and 1.1 percent for plant conversions from coal to cleaner fuels. By way of comparison, gas curtailments alone increased fuel costs by 6.5 percent. Thus, in terms of overall rate increases, the effect of environmental restrictions was relatively small.

V. INCREASES IN THE NON-FUEL COMPONENT OF RATES

Of the overall 6.0 mill increase in revenues per kilowatt hour during 1974, 2.5 mills (or 41.7 percent) represented increases in expenditures which were not associated with fuel. In determining the reasons for these increases in non-fuel charges, it is useful to segment the costs of service into three major categories:

(1) Operations and Maintenance (O&M) Expenses, excluding fuel;

(2) capital charges, further divided into

--Interest Expenses net of Allowance for Funds During Construction (AFDC),

--Preferred Stock Dividends, and

--Net Income Available for Common Stock; and

(3) other costs of service, including

--Taxes,

--Depreciation, and

--Other Income and Expenses.

These categories permit a useful separation of the costs of service into those which are determined in the short term in part by utility management (i.e., O&M excluding fuel), those fixed obligations which are determined primarily by past financing decisions but which fluctuate in any given year due to a continuing need for

external capital and the corresponding conditions of the capital market during this need (i.e., Interest Expenses and Preferred Stock Dividends), those which represent the return to the common stockholder after all other obligations have been met (i.e., Net Income Available for Common), and those which are primarily a function of the accounting procedures employed. Exhibit 15 summarizes the relative magnitude of each of these non-fuel cost components.

Non-fuel costs of service in 1973 were divided almost equally among Operations and Maintenance Expenses excluding fuel (32.7 percent), capital charges (31.5 percent), and other miscellaneous expense items (35.8 percent). During 1974, these non-fuel cost components increased in total by 16.8 percent (see Exhibit 5). O&M Expenses excluding fuel constituted approximately one-fourth of this amount, as did capital charges. The remainder was divided among the miscellaneous expense items, including the sum of Depreciation Charges, Taxes other than Income, Federal and State Income Taxes, and other Income and Expenses.

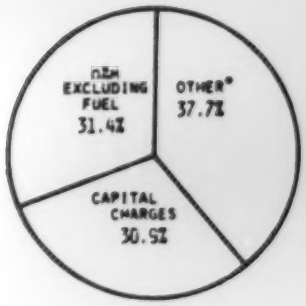
The following analysis has initially been segmented into these major components in the costs of service. At the same time, the underlying causes for the increases in the non-fuel component of rates will be discussed. The first of these causes, the impact of general price inflation, will be discussed primarily in terms of its effect on O&M Expenses. Second, the relationship between capital market conditions and the financial health of the electric utility industry will be explored. Third, the role of tax and accounting policies will be briefly surveyed, with the emphasis placed upon their impact on

EXHIBIT 15

NON-FUEL REVENUES PER KILOWATT HOUR BY COMPONENT
PERCENTAGE BREAKDOWN
1973-1974

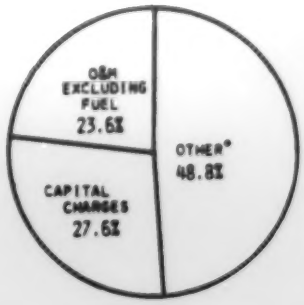
1973

PERCENTAGE BREAKDOWN
OF NON-FUEL REVENUES PER KILOWATT HOUR



1974

PERCENTAGE BREAKDOWN
OF NON-FUEL REVENUES PER KILOWATT HOUR



1973-1974

PERCENTAGE BREAKDOWN
OF CHANGES IN NON-FUEL REVENUES PER KILOWATT HOUR

* Includes the sum of Depreciation Charges, Taxes other than Income, and Federal and State Income Taxes less Other Income and Expenses.

Source: EEI Statistical Yearbook of the Electric Utility Industry
TBS Sample of Investor-Owned Utility Systems

internal cash generation. Finally, the magnitude of capital and operating expenditures for environmental control will be estimated.

Operations & Maintenance Expenses (excluding Fuel)

As can be seen in Exhibit 15, O&M Expenses excluding fuel have recently amounted to less than one-third of the non-fuel costs of service (and less than one-fourth of the revenue dollar when fuel is considered). These expenditures represent the only non-fuel costs of service which can be significantly modified in the short run by utility management. All the other expense items, with the exception of Net Income Available for Common, are associated with obligations essentially fixed in the short run in the form of financing charges, taxes, and depreciation.

During 1974, O&M Expenses excluding fuel increased approximately 12 percent. Given the overall 30.5 percent increase in the cost of service, the relative importance of these expenditures--as a percentage of non-fuel charges--declined from 32.7 percent in 1973 to 31.4 percent in 1974.

O&M Expenses include those associated with production, transmission, distribution, servicing customer accounts, and other sales, administrative, and general expenses which are not capitalized. The major component of these expenditures is payroll expenses. In the short run, management has few options for reducing overall O&M Expenses, and these options generally

involve a reduction in the work force--thus, cutting customer services, equipment maintenance, or both.[1] Although these options help alleviate a short-term requirement, many industry observers view them as unwise in the long run. Unless productivity can be increased, such costs of service must be covered by additional revenues.[2]

GENERAL PRICE INFLATION

O&M Expenses excluding fuel is the major area of expenses where the impact of inflation is felt directly in the form of either higher wages and salaries or expenditures for supplies. 1974 was the first year of double-digit inflation since the late 1940s.

Exhibit 16 provides a comparison of the Handy-Whitman index of utility costs and the GNP implicit price deflator for the 1960-1974 period. Over this period the overall rate of inflation within the economy as measured by the GNP price index averaged only 3.6 percent. However,

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[1] *In addition, management could capitalize some proportion of O&M Expenses by transferring, for example, maintenance employees to construction crews. While this would improve the statement of income, it would not eliminate the cash flow needs and would only defer the recovery of these expenses.*

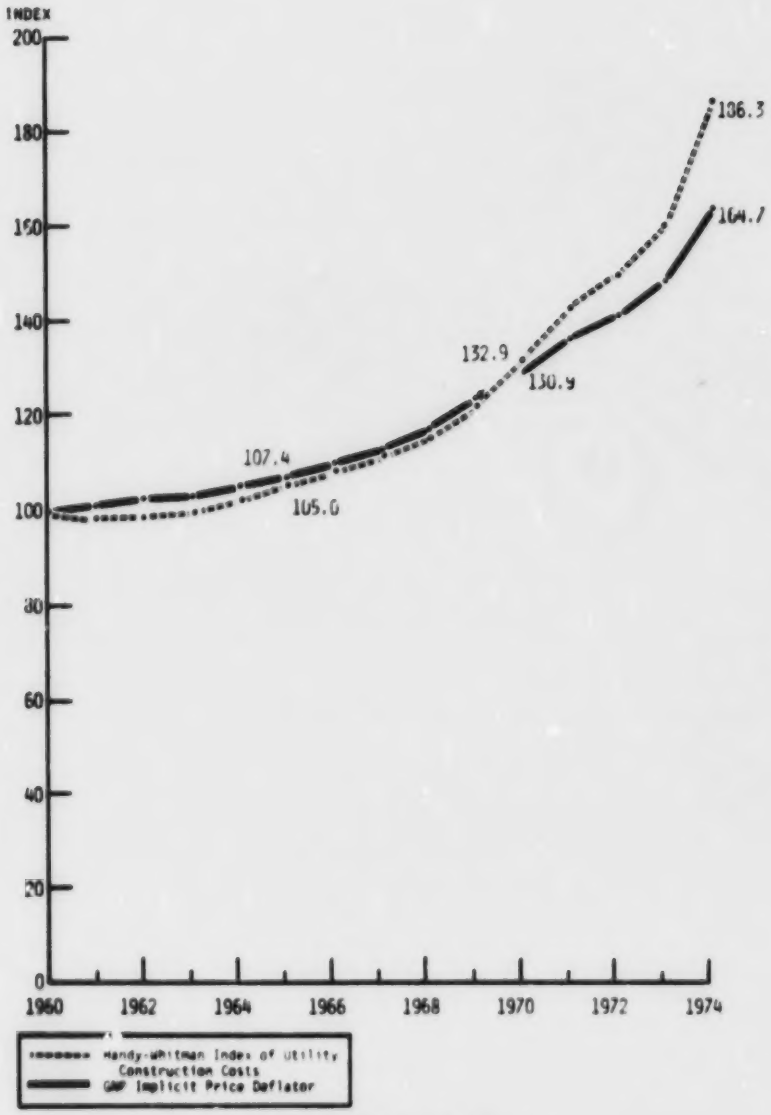
[2] *The opportunity for productivity increases is perhaps an area of significant opportunity. Elimination of work rule restrictions, for example, could also provide cost savings. It should be noted that, in the short run, these productivity gains would result in unemployment to the extent that these gains exceeded the growth in the use of electricity. Thus, the opportunity for cost savings without work force reductions has been exacerbated by energy conservation.*

EXHIBIT 16

ALTERNATIVE RATES OF INFLATION

1960 - 1974

1960 = 100



Source: Survey of Current Business, U.S. Department of Commerce
Business Statistics, U.S. Department of Commerce
FPC Statistical Yearbook of the Electric Utility Industry

the trend in the inflation rate has been disconcerting. During the early 1960s the rate of price increases averaged less than 1.5 percent. whereas the rate during the last half of the 1960s was approximately 4.0 percent. The rate during the 1970-1972 period increased slightly to 4.5 percent. Overall inflation during 1974 was 10.2 percent!

Inflationary pressures within the electric utility industry have been much more severe within the last few years.[3] The Handy-Whitman index followed the GNP price deflator quite closely during the 1960s. However. its rate of increase during the 1970-1973 period exceeded 6.7 percent. During 1974 this index of inflation within the utility sector soared by more than 15 percent.

CAPITAL CHARGES

The total electric utility industry had approximately $150 billion invested in plant and equipment by the end of 1974. This investment exceeds any other industry's level and has increased the industry's share of total plant investment within this country from

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[3] *Although the Handy-Whitman Index focuses upon construction costs, it is a representative measure of general price inflation within the electric utility industry.*

15 percent to nearly 20 percent during the last ten years. In addition, the industry is also the most capital intensive industry with the highest capital investment per dollar of annual sales--exceeding $4 of plant investment per dollar of sales.[4]

Because of its heavy capital investment and because the bulk of the funds required to meet these investment needs must be raised externally, the industry has been very susceptible to short-term swings in the capital markets. During the early 1970s, the industry was hit by major increases in financing costs. The increases were, however, alleviated either by declines in other costs of service, or by a healthy rate of growth within the industry in terms of kilowatt hour sales. Unfortunately, neither of these mitigating forces was operating in 1974. O&M Expenses were escalating. Moreover, the rate of growth in energy sales dropped precipitously from 1972 to 1974, and, because much of the industry's construction is a long-term commitment, the capital needs of the industry continued to grow by more than 12 percent.

Over the years, the electric utility industry has relied upon a capital structure that has been approximately 55 percent long-term debt, 10 percent preferred stock, and 35 percent equity. Associated with each of these components of the capital structure is a cost of service--interest expenses on long-term debt, a specified dividend rate for preferred stock, and Net Income Available

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[4] *Care should be taken in evaluating short-term changes in this ratio, since a significant increase in the cost of fuel would increase operating revenues without affecting capital expenditures.*

for Common. While the first two capital charges are fixed obligations, the return to the common stock shareholder depends upon the income remaining after all other costs of service have been met--including fuel, O&M Expenses excluding fuel, depreciation of plant and equipment, taxes, interest charges, and preferred dividends. Unfortunately, 1974 was extremely unkind to the holder of utility stocks.

Exhibit 17 summarizes the composition of capital charges by component for 1972 and 1974 as well as the composition of the increase in total financing costs during 1974. Because of a difference in rates of return, the percentage breakdown of capital charges by financing instrument differs substantially from the capitalization mix of 55/10/35 previously cited. During 1973, interest expenses net of the Allowance for Funds During Construction (AFDC) accounted for 31.5 percent of capital charges.[5] Preferred dividends accounted for another 10.9 percent, and the remaining 57.6 percent of the capital charges was in the form of Net Income Available for Common.

During 1974, interest charges increased by 36 percent. Dividends on preferred stock increased by nearly 16 percent. As a result of these fixed capital charges and the increase in the remaining costs of service categories, Net Income Available for Common increased by only 3 percent. Even more disconcerting from a cash flow perspective was that common stock

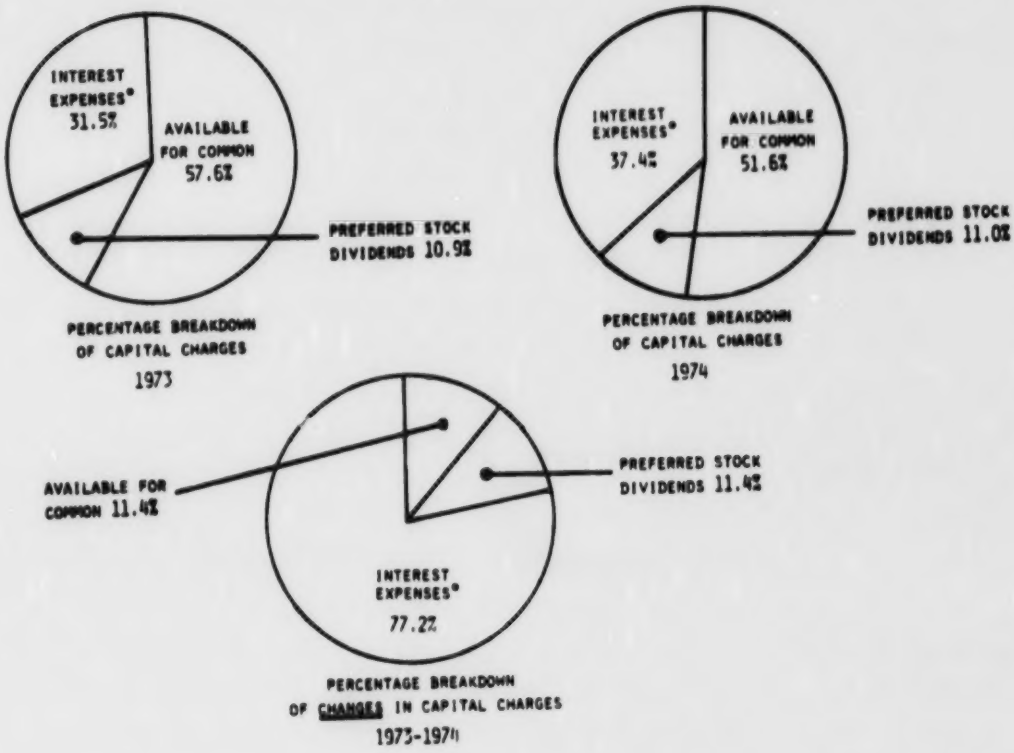
---

[5] *AFDC is a non-cash credit to income which reflects a partial allowance for the capital charges associated with construction work in progress. These credits are capitalized upon completion of the construction and earn the allowed rate of return throughout the useful life of the plant and equipment.*

EXHIBIT 17

CAPITAL CHARGES BY COMPONENT
PERCENTAGE BREAKDOWN

1973-1974


INTEREST EXPENSES* 31.5%
AVAILABLE FOR COMMON 57.6%
PREFERRED STOCK DIVIDENDS 10.9%
PERCENTAGE BREAKDOWN OF CAPITAL CHARGES 1973
INTEREST EXPENSES* 37.4%
AVAILABLE FOR COMMON 51.6%
PREFERRED STOCK DIVIDENDS 11.0%
PERCENTAGE BREAKDOWN OF CAPITAL CHARGES 1974
AVAILABLE FOR COMMON 11.4%
PREFERRED STOCK DIVIDENDS 11.4%
INTEREST EXPENSES* 77.2%
PERCENTAGE BREAKDOWN OF CHANGES IN CAPITAL CHARGES 1973-1974

*Interest Expenses net of Allowance for Funds During Construction (AFDC)

Source: EEI Statistical Yearbook of the Electric Utility Industry
TBS Sample of Investor-Owned Utility Systems

dividends increased, so that retained earnings actually declined by a slight amount (0.3 percent). Thus, approximately a 30 percent increase in operating revenues was translated into a 3 percent increase in Net Income Available for Common and a decline in retained earnings. Clearly, the common stock investor reaped no benefits from the higher costs of electricity!

CAPITAL MARKET CONDITIONS

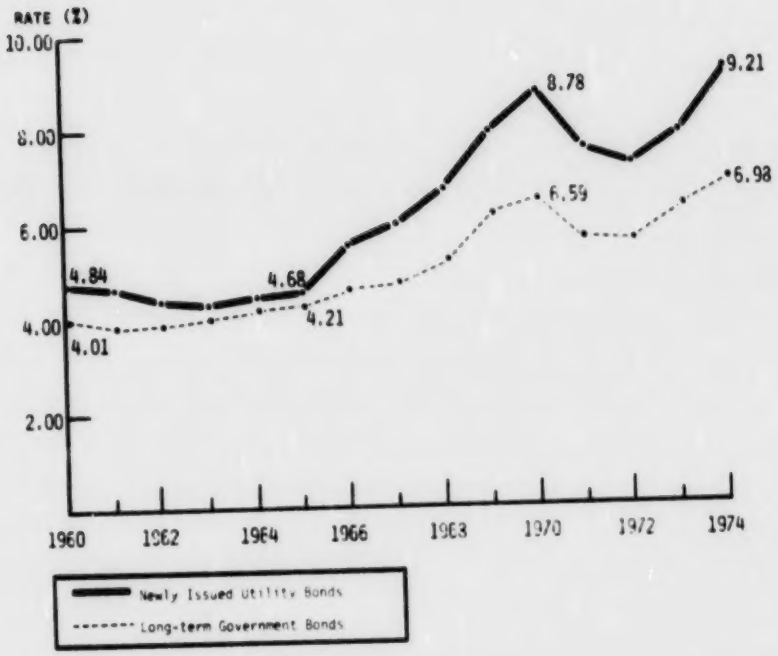
Unfortunately, the industry's deteriorating financial position fed back upon the industry in the form of higher costs for future financing. The combination of declining income and increasing costs of debt service reduces the ability of the utilities to cover their fixed interest charges. This decrease in the security of debt instruments has, over time, led to lower bond ratings, which are then reflected in a greater differential between the interest rate for long-term debt and an instrument with lower risk--for example, the rate of interest for long-term government securities.

For years, electric utility securities were viewed as virtually risk-free. This status permitted utilities to tap the capital markets frequently while maintaining relatively high bond ratings. During the last half of the 1960s there were only 20 downgradings of securities, and none of these reductions dropped a utility out of the upper three credit ratings--

Aaa, Aa, A. Moody's rating service downgraded another 15 securities during the 1970-1972 period with two-thirds of these among the upper rating bands. The Federal Power Commission published a compilation of downgradings that occurred during the first seven months of 1974 which noted that the ratings of 31 securities declined during this period. Of these, approximately 40 percent resulted in Baa or Ba ratings, and another 20 percent involved the suspension of ratings due to dire financial conditions.

The resulting differential in long-term interest rates is summarized in Exhibit 18. The spread between newly issued long-term securities of the electric utility industry and long-term government bonds fluctuated during the 1960s, approximating 0.8 percentage points in the 1960-1961 period, declining to 0.4-0.5 percentage points from 1962-1965, and then increasing steadily to 1.9 percentage points by 1969. The credit squeeze in 1970 drove the spread between these two long-term instruments up to nearly 2.2 percentage points. The relaxation in capital market conditions resulted in lower interest rates during the next two years and slightly decreased the spread between utility issues and government securities. Interest rates increased by 0.6 percent for both instruments during 1973. Government securities increased by about 0.6 percent in 1974, but interest rates on electric utility industry securities increased by more than 1.2 percent. Thus, the spread between these instruments

EXHIBIT 18
ALTERNATIVE FINANCING RATES
1960 - 1974



Source: Moody's Public Utilities Manual
Survey of Current Business, U.S. Department of Commerce
Business Statistics, U.S. Department of Commerce

once again increased to more than 2.2 percentage points, as the rate of interest on electric utility industry securities increased to more than 9.2 percent.

While interest rates for newly issued long-term utility debt were increasing from 4.8 percent in 1960 to 9.2 percent last year, the average rate of interest on outstanding long-term debt was increasing from 3.5 percent in 1960 to 7.1 percent during 1974. At the same time that the average yield on long-term debt was more than doubling, the average rate of return on common equity actually declined from 10.9 percent in 1960 to 10.6 percent in 1974. Exhibit 19 summarizes the average rates of return for each of the major financing instruments employed by the electric utility industry. Overall, the cost of capital for the industry climbed from 6.2 percent in 1960 to 8.3 percent in 1973. During 1974, the increase in fixed obligations and the decline in the actual return to common equity resulted in a stable cost of capital.

Actually, the embedded interest rate increased from 3.5 percent to 5.1 percent during the 1960s. Average rates of return on common equity increased very rapidly during the early 1960s and then declined somewhat during the latter half of that decade. While embedded interest rates shot up rapidly in the early 1970s, as the industry's capital requirements during this period exceeded the total external financing needs during the preceding 15 years, the rate of return on common equity declined slightly. Average rates of interest on long-term debt continued to increase during 1974, as the

Exhibit 19

AVERAGE RATES OF RETURN

1960-1974

(percent)

	Long-Term Debt	Preferred Stock	Common Equity	Overall Weighted Average*
1960	3.5	4.6	10.9	6.2
1965	4.0	4.5	12.5	7.0
1970	5.1	5.2	11.8	7.5
1973	6.7	6.3	11.5	8.3
1974	7.1	6.5	10.6	8.3

Based upon a fixed capitalization ratio of 55 percent long-term debt, 10 percent preferred dividends, and 35 percent common equity

Source: EEI Statistical Yearbook of the Electric Utility Industry
TBS Sample of Investor-Owned Utility Systems

average return on book value declined by nearly 1 percent to 10.6 percent.

The declining return on common equity and increasing return on other fixed financing obligations, coupled with the depressed stock market, drastically affected the attractiveness of the industry's common stock. Prior to 1970, the industry's stock sold at a market price substantially in excess of book value. Exhibit 20 summarizes the ratio of market price to book value.

The industry's market price to book value ratio increased from 1.69 times in 1960 to a high of 2.22 times in 1965. During the late 1960s, this relationship declined steadily from the 1965 level to 1.48 times in 1969. This trend continued in the 1970s. The ratio declined to 1.20 times by 1971, with a further decline to 0.93 times by the end of 1973. Thus, on average, the industry's stock was selling slightly below book value by the end of 1973. The ratio of market price to book value declined further during 1974, ending the year at 0.65 times.[6]

While this ratio reflects average conditions within the industry, one must fully understand the implication of an individual utility system being forced to sell its common stock at a price less than book value. Such a situation results in serious dilution in the value--and

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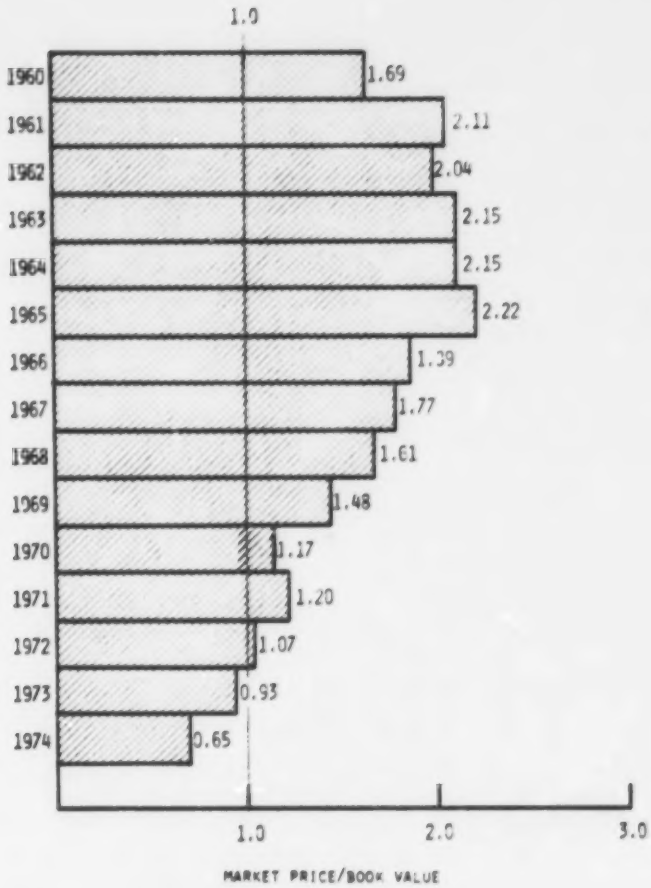
[6] *This ratio has improved somewhat during the First Quarter of 1975 to approximately 0.80 times, and has continued to improve during the Second Quarter.*

EXHIBIT 20
RATIO OF MARKET PRICE TO BOOK VALUE
1960-1974



Source: Moody's Public Utility Manual
185 Sample of Investor-Owned Utility Systems

attractiveness--of the common stock. Selling stock to meet capital needs when the market price is below book value drives earnings per share, dividends per share, and market price per share lower. Thus, the financing problem is further exacerbated by stock market conditions. By the end of 1974, the market price of common stock and interest coverages close to legal minimums virtually eliminated the opportunity for the industry to raise external capital under other than adverse conditions.

Utilities unwilling either to pay the higher rates of interest on long-term debt or to issue stock at prices below book value--because they were restrained from issuing more debt, because of interest coverage requirements, or because they were forecasting that long-term rates would decline and stock market conditions would improve--increased their short- to intermediate-term borrowing. During the last two years, this short-term borrowing further increased the interest obligations, since short-term rates have exceeded the long-term bond rates by more than 2.0 percentage points. These actions by utility executives have increased the aggregate of short-term debt and long-term debt due within one year from less than 3 percent of total capitalization in 1972 to more than 6 percent last year.

Fortunately, capital market conditions appear to be improving in 1975.

Other Non-Fuel Expenses

This "catch-all" component of rate increases captures miscellaneous income and expenses from non-electric operations, as well as those items which are determined by tax policies and accounting practices, for both book and tax purposes. The major items within this category--depreciation, Federal and state income taxes, and taxes other than income--all increased at a rate roughly comparable to the overall increase in the non-fuel component of rates. In discussing non-fuel expenses, the focus thus far has been on the statement of income. Given that the financial crisis within the industry has stemmed partially from an inability to generate cash internally, a brief analysis of recent trends in cash flow seems appropriate.

INTERNAL CASH GENERATION

Cash flow from operations differs from retained earnings by the amount expensed in the form of depreciation plus deferred taxes less the Allowance for Funds During Construction (AFDC). Each of these cash flow items will be discussed in turn.

Depreciation for book purposes has been relatively stable during the last few years at 2.7 percent of net utility plant per year. Since gross plant additions have been approximately 14.0 percent of net utility plant per year, depreciation by itself has amounted to less than one-fifth of the capital expenditures required for new plant and equipment.

Internal cash generation in an industry as capital intensive as the electric utilities depends heavily upon the accounting procedures employed within the investor-owned sector. These utilities can be divided into those which are required to use normalizing techniques and those which use flow-through accounting. The choice of accounting practice depends upon the procedures required by the relevant regulatory commission and impacts both the timing of cash flows emanating from capacity additions and the revenues required to yield a given rate of return.

Flow-through practices result in the benefits from accelerated depreciation and/or other tax incentives being passed on directly in the form of reduced consumer charges. On the other hand, those utilities which are permitted to normalize these benefits are able to generate additional cash flow because they can defer these items. A result of this difference in accounting requirements is reflected in the response of investors to utilities which use normalized and flow-through procedures. For example, the ratio of market price to book value was estimated to be 0.65 in 1974. The ratio for flow-through utilities was 0.49 during this period and 0.73 for normalizing utilities. Thus, utilities which are permitted to use normalization are able to generate more cash from operations and, as a result, are given somewhat better ratings by investors.

AFDC is a non-cash credit to income which reflects a partial allowance for the exclusion from the rate base of funds tied up in construction work in progress. These credits are capitalized upon completion of the construction and earn the allowed rate of return throughout

the useful life of the plant and equipment. The underlying concept behind AFDC is that those consumers who in the future will utilize this capital equipment should also pay the associated capital charges. Unfortunately, the financial needs of the utilities parallel the construction of new facilities, not their utilization.

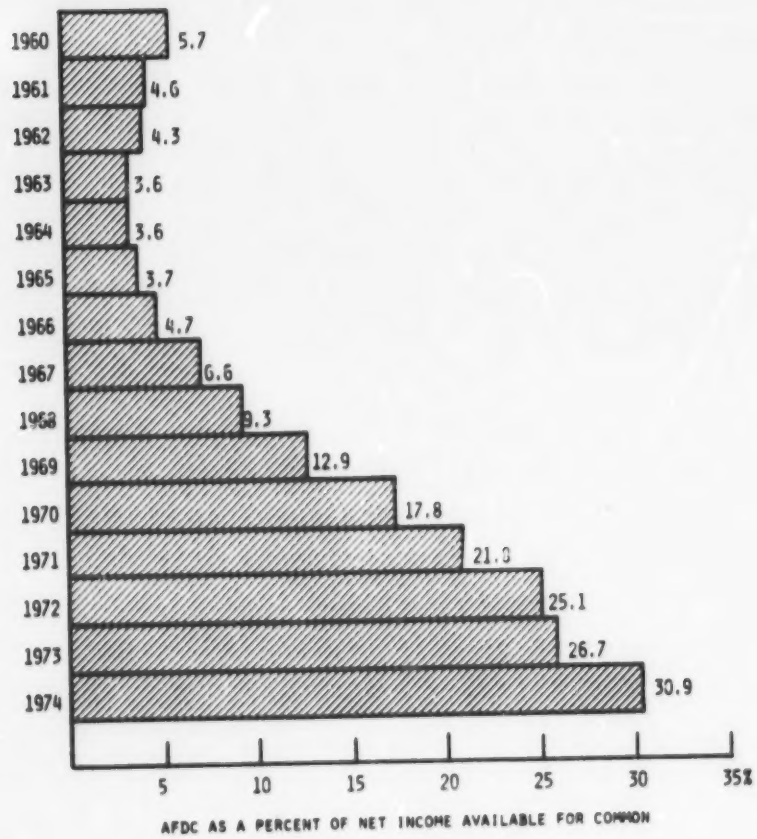
With the rapid growth of electricity usage throughout the 1960s and early 1970s, accompanied by a decline in economies of scale and significant escalation in construction costs, the role of AFDC increased from a low of 3.6 percent of Net Income Available for Common in 1963-1964 to 30.9 percent in 1974. Exhibit 21 details this relationship between AFDC and Net Income Available for Common.

Net Income Available for Common represents two items--common stock dividends and retained earnings. Clearly, cash available from earnings retained within a firm is depleted to the extent that dividends are paid. Historically, the investor-owned utilities have paid out approximately two-thirds of income in the form of dividends on common stock. Internally generated cash has been further depleted by the steady increase in AFDC.

By 1974, the non-cash credit to income in the form of AFDC had exceeded the level of earnings retained within the industry. Exhibit 22 summarizes the steady increase in AFDC as a percent of retained earnings from a low of 11.5 percent in 1965 to the 110.3 percent registered in 1974. Unfortunately, this adverse cash flow could not be balanced by a significant decrease in the

EXHIBIT 21

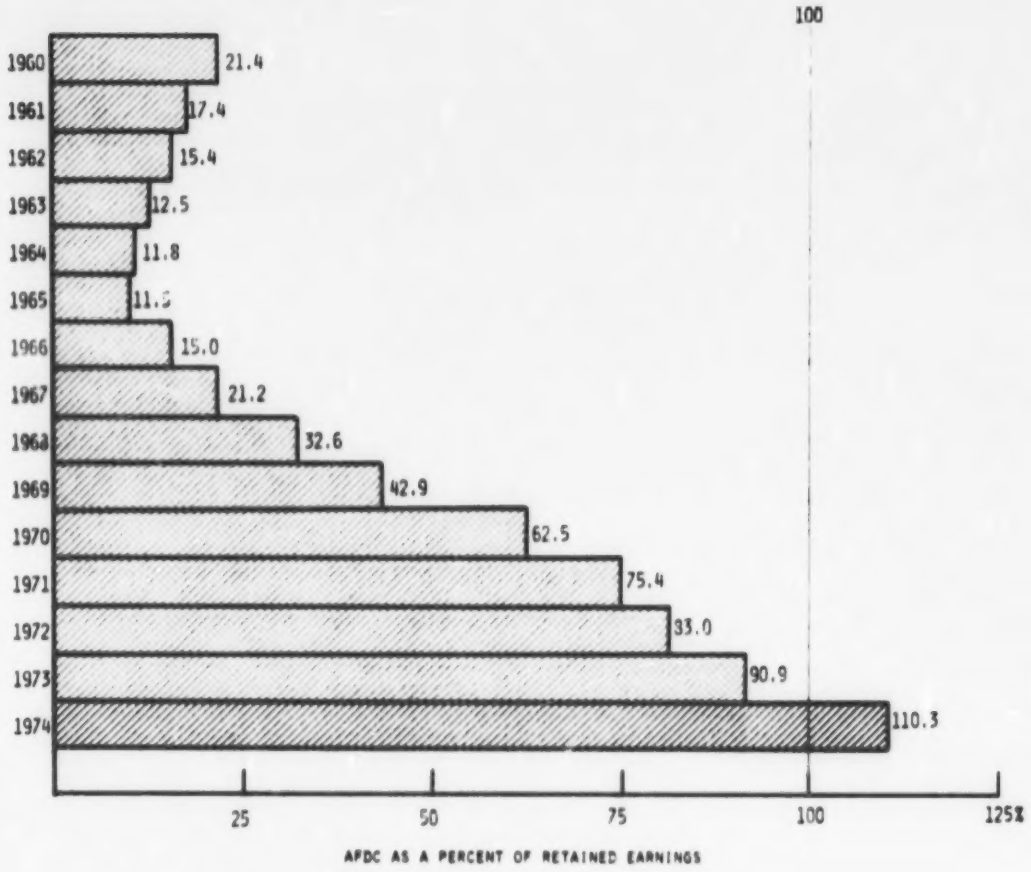
RELATIONSHIP BETWEEN ALLOWANCE FOR FUNDS DURING CONSTRUCTION
AND NET INCOME AVAILABLE FOR COMMON
1960 - 1974



Source: EEI Statistical Yearbook of the Electric Utility Industry
TBS Sample of Investor-Owned Utility Systems

EXHIBIT 22

RELATIONSHIP BETWEEN ALLOWANCE FOR FUNDS DURING CONSTRUCTION
AND RETAINED EARNINGS
1960 - 1974



Source: EEI Statistical Yearbook of the Electric Utility Industry
TBS Sample of Investor-Owned Utility Systems

proportion of income paid out in dividends. Such a policy would have further depressed the attractiveness of the industry's stock.

Thus, the industry's ability to generate cash internally has been severely restricted at a time when the needs for financing were great and the external capital was available only under extremely adverse conditions.

Pollution Control Expenditures

The early 1970s was a period in which significant steps were taken to legislate improvements in the nation's environment, most notably in the form of the Clean Air Act of 1970 and the 1972 Amendments to the Federal Water Pollution Control Act. These legislative actions necessitate capital expenditures for such pollution control equipment as precipitators, scrubbers, cooling towers, etc. Most forecasts of the overall impact of environmental legislation cite the electric utility industry as the most severely affected on an absolute dollar basis.

It is extremely difficult to separate the impact of increases in capital expenditures for pollution control equipment on utility rates from the impact of other capital expenditures. There are at least three underlying reasons for this problem. First, the uniform system of accounting required for reporting the financial and operating conditions of electric utilities does not differentiate expenditures for pollution control equipment.

Second, no direct evidence of the operating implications (for example, capacity penalties) is reported. Finally, investor-owned utilities can benefit from classifying some expenditures as being for environmental reasons.

Recognizing the need for more detailed reporting of expenditures for pollution control, the Federal Power Commission recently proposed to collect and report the costs of environmental protection facilities and activities, including the cost of assets and operating expenses.[7] Early this year, the Federal Power Commission revised its FPC Form 67-A. In association with this revision, a notice of proposed rulemaking required utilities to complete a questionnaire of their plans and their estimated costs for meeting current air pollution standards.[8] Although these data will be interesting, they will not address directly the total impact of environmental regulations on costs of service.

Even with these additional reporting requirements, certain adverse operating conditions associated with pollution control equipment will not be clearly specified. For example, recent estimates of the reduction in generation capability resulting from the installation of closed-cycle cooling include a 2 percent capacity penalty, due to increased turbine back-pressure, and an additional 1 percent penalty, due to operating requirements for the cooling tower itself. These penalties impose additional fuel

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[7] *RN-75-5 published 29 August 1974 with comments to be filed by 15 October 1974.*

[8] *RN-75-18 published 21 February 1975 with forms to be submitted by 1 May 1975.*

requirements and necessitate the installation of additional generation equipment to offset the reduced capacity.[9]

The specification of general rate increases associated with pollution control equipment is futher complicated by the incentive for industry representatives to overstate the cost of such equipment. For example, pollution control expenditures are eligible for financing in the form of Pollution Control Bonds and/or Notes, as well as Industrial Revenue Bonds. These financing instruments, while limited in their availability, offered interest rates 2 to 3 percent below those available on long-term debt during 1974, due to their special tax status. Pollution Control Bonds and Notes represented approximately 6.5 percent of external financing during 1973 and 1974.

There are also expenditures where their classification is not absolutely clear. As an example, in classifying the expenditures associated with the installation of cooling towers on a new generating unit, one must determine initially whether closed-cycle cooling would have been installed in the absence of environmental legislation. If so, should any cost at all be allocated

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[9] *Preliminary estimates of the capacity loss associated with certain technologies and/or fuel conversions to meet the Clean Air Act standards are significantly greater than these estimates.*

to the environmental movement? If not, should pollution control equipment be defined as the total amount expended, as the difference between expenditures for closed- and open-cycle cooling systems, or as some other amount? In this latter case, it is doubtful that detailed engineering cost estimates would be available for both types of cooling system.

In attempting to determine the proportion of non-fuel charges associated with the installation and operation of pollution control equipment, TBS interviewed executives from nearly a score of utilities, seeking their assessment of the impact of environmental legislation on utility rates.[10] While most could articulate the ways in which environmental restructions affected their operations and could provide their own estimates of the impact on rates, few had comprehensive data available.

The executives interviewed at Commonwealth Edison were a notable exception. The following brief table summarizes, through 30 September 1974, the factors increasing Commonwealth Edison's price of electricity since 1971, as a percent of the price increase.[11]

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[10] *See Appendix B for a list of the utility systems interviewed during this study.*

[11] *Once again, this increase reflects changes since 1971. The impact of plant conversions to oil and increased utilitization of low-sulfur coal prior to 1971 has been excluded from this analysis.*

Fuel		33.8%
Non-Fuel		
O&M Expenses Excluding Fuel		30.8%
Environmental Requirements	2.5%	
Other Reasons	28.3	
Taxes		18.7
Capital Charges (including Depreciation)		16.7
Environmental Requirements	1.5%	
Construction Cost Escalation	8.5	
Increased Cost of Money	3.8	
Decreased Return on Common Equity	(2.4)	
Other Reasons	5.3	
Total Non-Fuel Increases		66.2%
Total Rate Increase		100.0%

Thus, environmental requirements accounted for approximately 9 percent of the increase in O&M expenses excluding fuel, capital charges and depreciation.

A second source of the contribution of pollution control equipment to overall non-fuel rate increases can be gleaned from McGraw-Hill's 8th Annual Survey of Pollution Control Expenditures. Each year the Economic Department of McGraw-Hill Publications Company surveys all industries to estimate the cost and timing of expenditures needed to bring existing facilities up to present pollution

control standards.[12] In their most recent study, McGraw-Hill concluded that, during 1974, 7.1 percent of capital expenditures within the electric utility industry were allocated to pollution control equipment. A year earlier, McGraw-Hill had reported a 7.6 percent allocation for pollution control equipment for 1973, and had indicated that the industry planned to spend 8.3 percent during 1974. Thus, pollution control expenditures were less, on a percentage basis, than expenditures in the previous year, and were also less than had been planned.

Summary

It is unfortunate that better information is not available on the impact of pollution control expenditures. Based upon the above-mentioned sources, however, one can conclude that approximately 7 to 9 percent of the increased non-fuel costs of service can be attributed to other than economic reasons--that is, environmental reasons. Since the non-fuel component represents 41.7 percent of overall 1974 rate increases, approximately 3 to 4 percent of the total 1974 increase in rates can be attributed to pollution control expenditures.[13]

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[12] *These estimates appear to exclude pollution control expenditures required for new facilities.*

[13] *It should be noted that this excludes the previously mentioned 1.6 percent increase associated with the fuel component of the rate increase.*

VI. OTHER ISSUES RELATING TO UTILITY RATES

While the previous chapters have focused on the increase in revenues per kilowatt hour that occurred in 1974, little attention has been given to such factors as regulatory lag and energy conservation. No analysis of 1974 electric rates can be considered complete without a discussion of these factors, which, although not directly affecting the costs of service, nonetheless contributed to the industry's problems.

Regulatory Lag

Industry executives (and some Federal government officials) frequently complain that the delay in pending rate increases has seriously compounded the financial problems facing the industry. During the 1960s, when both the average costs of service and electric rates were declining, utility management did not argue strongly for a reduction in the delays that were then evident in the regulatory process. Delays in implementing rate decreases were to their advantage. The tumultuous conditions during the last year argue strongly, however, for a reduction in the average time required to grant a rate request.

In order to recover higher costs of service, electric utilities must apply to and receive the approval of regulatory commissions. With few exceptions this process has been characterized by prolonged delays. In fact, most states utilize the maximum suspension period to evaluate requests for rate relief.

This evaluation of utility rate requests generally includes the filing of legal briefs by the utility and other interested parties. Although each state has its own set of procedures, the filing of these briefs is generally accompanied by public hearings, and both processes focus upon the rate base, the allowed rate of return, and allowable operating expenses during the test period, however defined.[1]

During the last year, the average period of delay in the effective date of completed rate requests by the investor-owned utilities within the TBS sample was 248 days, ranging from a low of 15 to a high of 539 days. These delays reduced industry revenues by approximately 7.1 percent.

If investor-owned electric utilities had received these rate requests without delay, the actual rate of return on common equity could have increased from 10.6 percent to over 13 percent.[2] Under these conditions, the average cost of electricity would have escalated by nearly 40 percent.

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[1] *The rate base issue includes the specification of the assets (for example, plant and equipment, construction work in progress, working capital, etc.) to be included, the valuation standard (for example, original cost, fair value, etc.) to be applied, and the test period (for example, average or year-end) to be employed. The allowed rate of return generally depends upon the capital structure assumed and the rate of return permitted on each financing instrument. Allowable operating expenses include the specification of all costs of service with the exception of fuel (other than the base amount included within the general rate) and capital charges.*

[2] *This computation assumes that one-half of taxes other than income are linked to gross revenues and that the marginal income tax rate is 50 percent.*

While no one could expect regulatory lag to be completely eliminated, a reduction in the delays inherent in the regulatory process could significantly improve the earnings of investor-owned utilities. For example, the following table summarizes what the relationship between regulatory lag and actual return on common equity would have been during 1974.

Regulatory Lag	Increased Revenues	Actual Return on Common Equity
none	7.1%	13.2%
3 months	4.5%	12.2%
6 months	2.0%	11.3%
actual (248 days)	-	10.6%

Clearly, any improvement in the time required to process a rate request would alleviate the financial problems now facing the industry.

Energy Conservation

A utility's forecast of revenue requirements reflects the anticipated costs of service allocated over an estimated level of kilowatt hour sales by means of prescribed rate structures. If actual electricity usage were to correspond to these estimates, utilities would achieve the revenue levels required to provide net income equal to the allowed rate of return. If usage is greater than forecast and costs do not exceed their estimated levels, revenues and net income will exceed expectations. If, on the other hand, estimated usage exceeds actual

levels, net income will be impaired. This latter event occurred during 1974.

During the 1960s and early 1970s, the average electric usage per customer and the number of electric customers increased by approximately 5 percent and 2 percent per year, respectively. Total electric usage thus increased by more than 7 percent per year with little year-to-year deviation. In no year did the growth in electricity exceed 9 percent or drop below 5 percent.

This steady trend in electricity usage came to an abrupt halt in 1974, when a combination of factors resulted in an absolute decline in the average usage per customer in excess of 3 percent and a decline in total electrical usage of approximately 1 percent. These data, along with other components of electric revenues, are summarized in Exhibit 23.

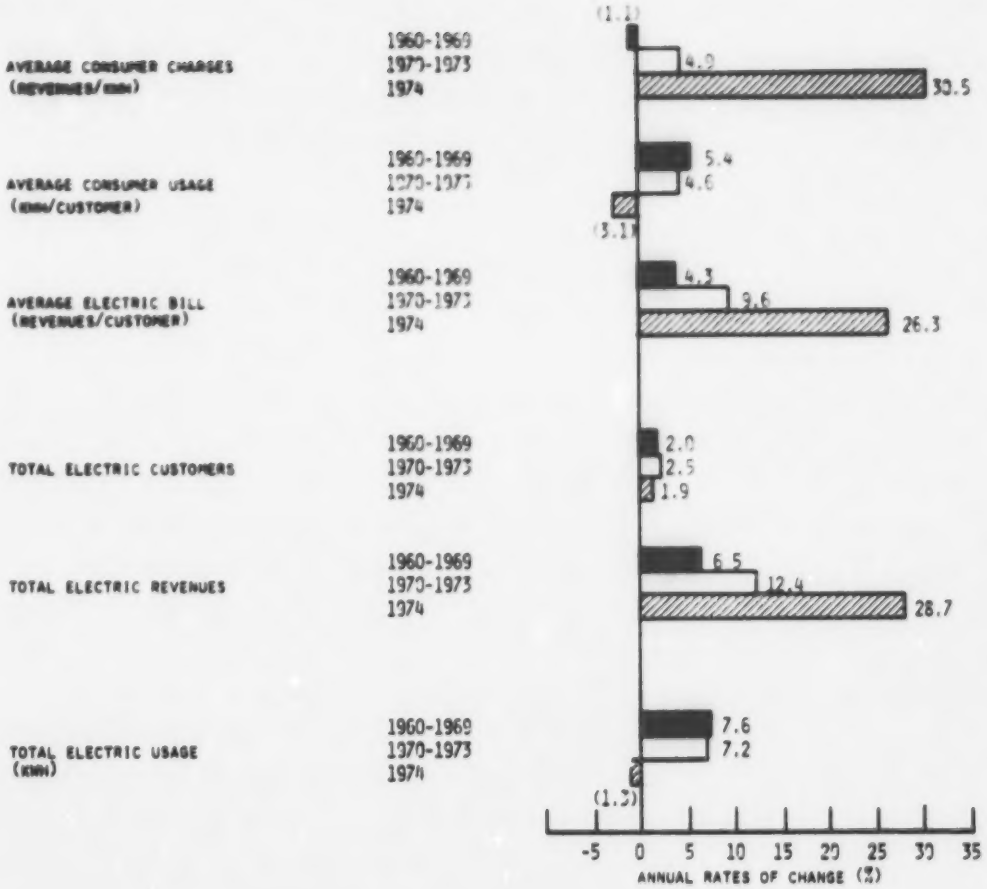
While the primary factor underlying this decline in electricity usage was the non-price induced energy conservation that accompanied the Arab oil embargo, increased consumer charges for electricity and the general economic decline sustained the reduced levels of usage throughout 1974.

If energy conservation had not occurred, average revenues per kilowatt hour most likely would have been slightly lower due to the declining block structure of existing rate schedules. However, increased usage would have reduced the impact per kilowatt hour of fixed

EXHIBIT 23

ANNUAL RATES OF CHANGE FOR COMPONENTS OF ELECTRIC REVENUES

1960-1974



Source: EEI Statistical Yearbook of the Electric Utility Industry
TBS Sample of Investor-Owned Utility Systems

obligations--depreciation, interest expenses, and preferred dividends--and increased net income. For example, the actual return on common equity could have exceeded 13 percent if the growth in electricity had been approximately 7 percent.[3] Of course, under these circumstances much of the emergency rate relief requested and, in some cases, granted during 1974 would not have been required.

In the short term, the impact of energy conservation depends upon managements' anticipation of the decline in electricity usage. If energy conservation were anticipated and included in the computation of revenue requirements, the short-term impact would be a request for higher rates per kilowatt hour to offset the reduction in kilowatt hour sales. If unexpected, energy conservation would result in revenue deficiencies and a lower return on net income. Clearly, the decline in usage during 1974 was not anticipated!

In the long term, energy conservation will result in slightly lower rates as less capital investment will be required for generating facilities. Using the alternative growth assumptions specified by the Technical Advisory Committee on Finance (National Power Survey), which were incorporated in prior TBS analyses[4],

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[3] *This computation assumes that average fuel charges are unchanged, that one-half of taxes other than income are linked to gross revenues, and that the marginal income tax rate is 50 percent.*

[4] *See, for example, Economic Analysis of Effluent Guidelines--Steam Electric Powerplants (December 1974) or the testimony of Howard W. Pifer III before the Subcommittee on Health and the Environment, Committee on Interstate and Foreign Commerce, United States House of Representatives (March 19, 1975).*

a decline in the growth of electricity during the next decade from the historic rate to a more moderate growth rate would reduce capital expenditures by nearly $40 billion.

APPENDIX A
A SUMMARY OF OTHER RECENT ELECTRIC RATE STUDIES

A number of government and private groups provide annual surveys of electric rates. These studies prescribe different methodologies for evaluating the magnitude of rate increases, utilize different measures for determining the amount of increases, and often reach quite different conclusions.

For example, some studies concentrate upon the typical electric bill for a given customer. In so doing, they compute the total monthly bill for a given rate structure and level of usage. Since rate structures vary somewhat among utilities and are generally revised after each general rate increase, typical electric bills do not provide an accurate measure of changes on an annual basis. Another common approach is to summarize all rate increases which have been granted by and/or are pending before regulatory commissions.

Perhaps the most detailed information on national, regional, or statewide trends is provided in the Edison Electric Institute's Statistical Yearbook of the Electric Utility Industry. This document has been used within this study to provide historical perspective from 1960 through 1973. Unfortunately, data for 1974 are currently unavailable.

A common deficiency in each of the above-mentioned methodologies is that they focus on rate increases with little or no attention placed upon documenting the reasons underlying changes in rate levels. Public policy-makers require data that not only detail current trends but also isolate the root causes, thus, hopefully providing an indication where their attention should be directed if the overall trend is unacceptable. For this reason, the primary focus of this study has been an attempt to document the relative impacts of alternative reasons for the significant rate increases that occurred in 1974.

The remainder of this appendix summarizes four studies that have recently been released and have received nationwide attention. The methodologies employed and the group publishing each survey are as follows:

- typical electric bills
  - --Federal Power Commission
  - --National Utility Service, Inc.
- rate revisions granted and/or pending
  - --Ebasco Services, Inc.
- analysis of fuel adjustment clauses
  - --Congressional Research Service, Library of Congress

Federal Power Commission

Each year, the Federal Power Commission (FPC) publishes comprehensive nationwide data on net monthly bills as of 1 January for typical residential, commercial,

and industrial services. In its most recent publication dated December 1974, the FPC reported typical bills as of 1 January 1974, thus providing a comparison between 1 January 1973 and 1 January 1974. These data are summarized in Exhibit A-1.

For example, typical residential electric bills increased between 9 percent and nearly 14 percent during 1973 with the greater percentage increase being absorbed by the larger residential user. While these percentage increases are approximately double those reported by both the Edison Electric Institute and the TBS sample of investor-owned utilities, the general conclusions reached are not necessarily different from those cited within this report.

First, the differences in reporting periods must be recognized. The FPC computes its typical electric bill once a year as of 1 January, whereas the Edison Electric Institute and TBS use the broader basis of average increases in revenues per kilowatt hour over the entire year. Since the Arab oil embargo occurred very late in 1973 and much of its impact was not felt until 1974 due to time lags in the collection of increased fuel costs, typical bills as of 1 January 1974 would overstate the rate of increase in rates during 1973. Much of the rate of increase attributed to 1973 in fact occurred during the last quarter of 1973.

Second, the rate of increase in typical commercial and industrial bills exceeds that of the typical residential customer. Given that revenues from commercial customers are approximately equal to those from the industrial sector, the FPC data indicate that commercial bills increased less than residential bills, but industrial bills

Exhibit A-1

TYPICAL ELECTRIC BILLS
FEDERAL POWER COMMISSION
January 1, 1973 vs. January 1, 1974

	Typical Bill Jan. 1, 1973	Typical Bill Jan. 1, 1974	Percent Increase
Residential			
250 kWh	$ 8.67	$ 9.74	9.2%
500 kWh	12.56	14.10	12.3
750 kWh	16.96	19.14	12.9
1,000 kWh	21.85	24.85	13.7
Commercial			
6 kW - 750 kWh	$ 31.80	$ 34.25	7.7%
12 kW - 1,500 kWh	62.53	68.57	9.7
30 kW - 6,000 kWh	193.67	215.35	11.2
40 kW - 10,000 kWh	285.97	320.51	12.1
Industrial			
150 kW - 30,000 kWh	$ 790.00	$ 899.00	13.8%
300 kW - 60,000 kWh	1,457.00	1,685.00	15.6
1,000 kW - 200,000 kWh	4,402.00	5,196.00	18.0

Source: Federal Power Commission, Typical Electric Bills

increased significantly more than those for residential customers. On average, the typical commercial and industrial bill escalated more than the residential bill.

Third, the report supports the conclusion that not only did large users (i.e., industrial) absorb a higher rate of increase in electric bills than small users (i.e., residential), but also larger users within a given customer class had the largest rate increases.

There is no doubt that the FPC's Typical Electric Bills is a valuable summary of rate increases. The report is comprehensive in its detail (by customer type and size) and its coverage (nationwide). Unfortunately, the report covers rates as of a single day and, therefore, cannot provide information on the average increase over a given time period--for example, a year. In addition, the report is published near the end of the following year, and as a result, its use is limited to providing historical perspective.[1]

National Utility Service, Inc.

During March, National Utility Service (NUS) released a survey of typical electric rates during June 1973 and December 1974 for large industrial users in Europe, North America, Australia, and South Africa. A summary of their findings has been provided in Exhibit A-2.

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[1] *Beginning in 1975, the National Association of Regulatory Utility Commissioners began a series of quarterly reports on residential electric utility bills to be used in conjunction with the FPC Typical Electric Bills. Unfortunately, no summary of this raw data has been made available.*

Exhibit A-2

TYPICAL ELECTRIC BILLS
NATIONAL UTILITY SERVICE, INC.
June 1973 vs. December 1974

	Revenues per Kilowatt Hour (in mills)		Percent Increase
	June 1973	December 1974	
Europe			
Belgium	22.6	41.9	85.4%
France	17.4	22.3	28.1
Germany	29.3	39.3	34.1
Italy	15.6	28.6	83.3
Netherlands	19.8	22.7	14.6
United Kingdom	17.5	28.2	61.1
Canada	12.2	14.1	15.6
United States	16.8	27.1	61.3
Australia	20.7	22.0	6.3
South Africa	11.8	14.4	22.0

Source: National Utility Service, Inc., Survey of Comparative Electric Costs for Major Utilities in Europe, North America, Australia, and South Africa

While the NUS study was timely and provided a useful worldwide perspective, it lacks the comprehensive coverage found in the FPC study of typical electric bills. For example, NUS relied upon data from 15 large utility systems within the United States for a single customer type and size. Unfortunately, that "typical" customer was selected to be a customer whose rate was based upon 1,000 kilowatts and 450,000 kilowatt hours of usage.[2] By way of contrast, the largest "typical" industrial customer reported by the FPC had the same kilowatt demand, but used only 200,000 kilowatt hours.

Using its sample of 15 utility systems within the United States, NUS estimated that the average cost per kilowatt hour was 16.8 mills in June 1973 and 27.1 mills per kilowatt hour in December 1974--an increase of 37.5 percent per year.[3] These changes can be compared with the 1973 EEI average for commercial and industrial customers of 16.9 mills per kilowatt hour and the TBS-computed increase of 33.1 percent for these customers during 1974.

Ebasco Services, Inc.

Each year Ebasco compiles a list of electric rate requests granted and/or pending for all investor-owned utilities from various published sources. In its

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[2] *In addition, this typical NUS customer owned his own transformer.*

[3] *It should be noted that NUS reports percentage increases for an 18-month period, not on an annual basis.*

most recent publication, Ebasco reported that rate increases granted during 1974 amounted to $2.3 billion, with another $2.0 billion of requests outstanding at the end of the year. A summary of rate increases (and decreases) during the period 1960-1974 is provided in Exhibit A-3.

Comparisons of the Ebasco study with other studies are made difficult since Ebasco limits its data gathering in most cases to general rate increases, thus excluding increases associated with fuel adjustment clauses. In addition, its report is compiled from lists taken from various secondary sources (newspapers, trade journals, etc.) which, while they are believed to include a great proportion of increases, may be incomplete. Finally, the Ebasco methodology gathers information on general rate increases that have been granted. While these increases are often stated in terms of additional revenues on an annual basis, the collection of these revenues does not coincide with the calendar year and, therefore, cannot easily be compared with rate increases during a calendar year.

Congressional Research Service

Last November, Senators Muskie and Metcalf requested information from state regulatory commissions on the electric rate increases attributable to fuel adjustment clauses. On the basis of responses from 37 of the regulatory commissions for 10 or 11 months of 1974, the Congressional Research Service, Library of Congress,

Exhibit A-3

RATE REVISIONS GRANTED AND PENDING
EBASCO SERVICES, INC.
1960-1974
(millions of dollars)

	Rate Increases		Rate Decreases
	Granted During Period	Pending at End of Period	Granted During Period
1960-1964	$ 114.7	$ 0.3	$208.9
1965-1969	199.1	490.3	227.7
1970-1974	5,548.9	2,043.1	6.0
1970	$ 430.6	$ 629.8	$ 4.5
1971	802.7	970.5	1.0
1972	827.1	906.7	-
1973	1,150.8	1,566.5	-
1974	2,337.7	2,043.1	-

Source: Ebasco Services, Inc., Investor-Owned Utility Rate Revisions, Increases and Decreases, Granted and Pending

estimated that nationwide rate increases during 1974 totaled $7.7 billion with $5.3 billion resulting from fuel adjustment clauses.

In focusing on increases due to fuel adjustment clauses, this study vastly overstated the rate of increase since these clauses generally represent all of the increase in fuel charges but exclude the fuel charges included within the general rate structure. Thus, for example, the previously stated 72.9 percent increase in the fuel component of the 1974 rate increase would be reported as a 194.4 percent increase if 3.0 mills of the fuel charge were assumed to be in the general rate.

Overall, the Congressional Research Service study estimates rate increases of $7.7 billion. This amount compares with the TBS estimate of approximately $9.1 billion based upon 1973 revenues of $31.7 billion reported by the Edison Electric Institute and the TBS estimate of a 28.7 percent increase in total electric revenues. This $9.1 billion breaks down into a $5.3 billion increase in the fuel component and a $3.8 billion increase in non-fuel charges.

The TBS estimate of increases in fuel charges equals the Congressional Research Service increases due to fuel adjustment clauses. However, the TBS estimate of a $3.8 billion increase in non-fuel charges exceeds the Congressional Research Service estimate of general rate increases by $1.4 billion (and the Ebasco estimate by approximately $1.5 billion). No apparent reason for these differences can be found other than those previously

discussed with regard to Ebasco and the additional adjustments undertaken by Congressional Research Service to compensate for incomplete reporting.

APPENDIX B
TBS SAMPLING PROCEDURES

In order to determine the magnitude of utility rate increases during 1974, TBS developed nationwide samples of investor-owned utilities and utility rate managers to obtain both specific quantitative data and descriptive information.

Statistical Sample

The primary sample of electric utilities was composed of the largest investor-owned utility (in terms of kilowatt hours sold to ultimate customers) in each of the 48 contiguous states plus the District of Columbia, with the exception of Nebraska and Tennessee which are dominated by public utilities. These 47 utility systems were then segmented into the nine Bureau of Census geographic regions detailed in Exhibit B-1. These are also the regions used extensively by the Edison Electric Institute. Exhibit B-2 provides a listing by region of those electric utility systems included in the TBS sample.

In selecting only investor-owned utilities, it was recognized that these utilities represent a majority of sales to ultimate customers and, with few exceptions, provide financial and operating data on a consistent and timely basis. As can be seen in Exhibit B-3, investor-owned utilities represented more than 78 percent of the kilowatt hour sales to ultimate customers in 1973. In

Exhibit B-1

BUREAU OF CENSUS GEOGRAPHIC REGIONS

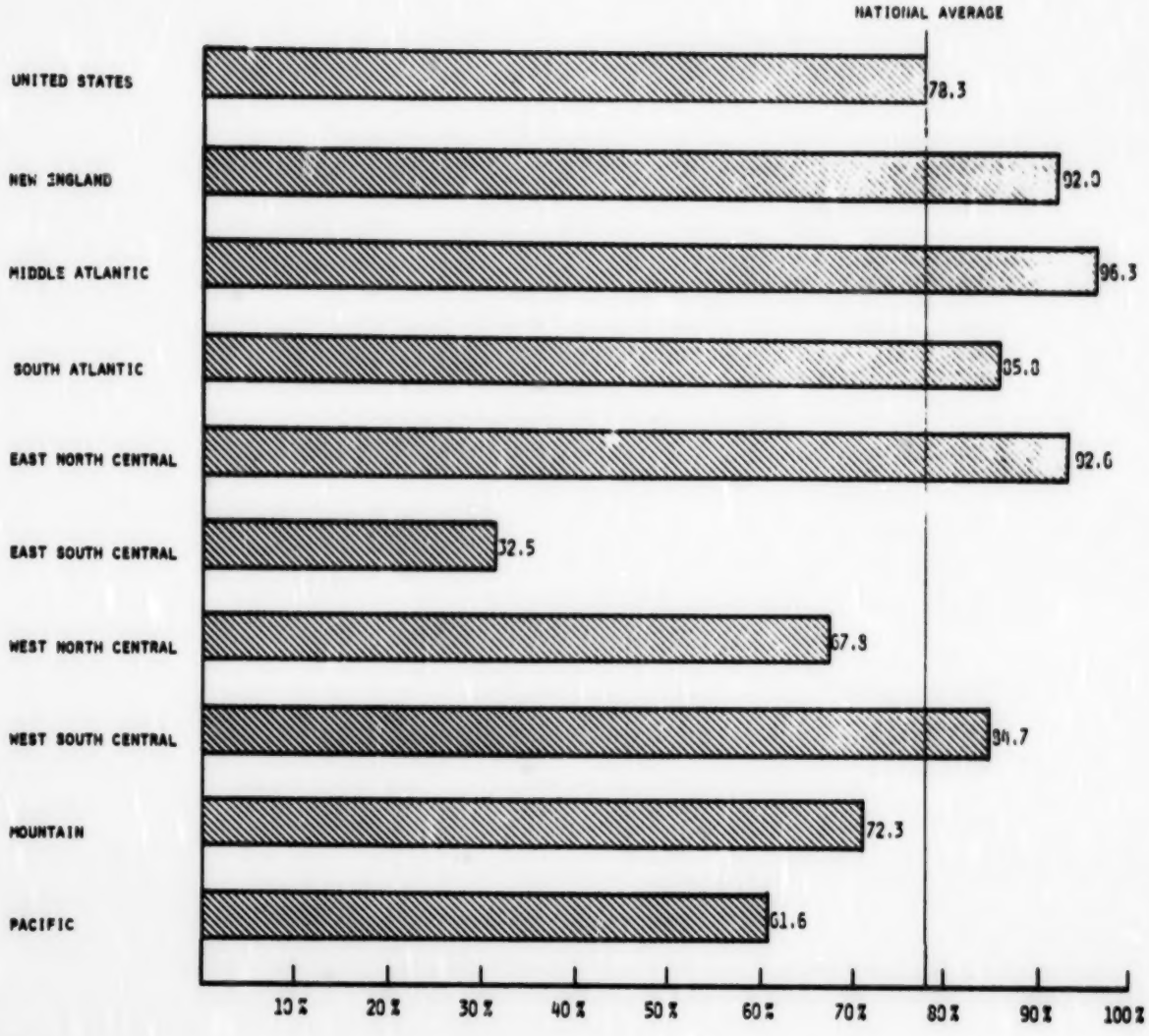
EXHIBIT B-2

TBS SAMPLE OF INVESTOR-OWNED UTILITIES

NEW ENGLAND	
CONNECTICUT	CONNECTICUT LIGHT & POWER COMPANY
MAINE	CENTRAL MAINE POWER COMPANY
MASSACHUSETTS	MASSACHUSETTS ELECTRIC
NEW HAMPSHIRE	PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
RHODE ISLAND	NARRAGANSETT ELECTRIC
VERMONT	CENTRAL VERMONT PUBLIC SERVICE COMPANY
MIDDLE ATLANTIC	
NEW JERSEY	PUBLIC SERVICE ELECTRIC & GAS COMPANY
NEW YORK	CONSOLIDATED EDISON COMPANY OF NEW YORK
PENNSYLVANIA	PHILADELPHIA ELECTRIC COMPANY
SOUTH ATLANTIC	
DELAWARE	DELMARVA POWER & LIGHT COMPANY
DISTRICT OF COLUMBIA	POTOMAC ELECTRIC POWER COMPANY
FLORIDA	FLORIDA POWER & LIGHT COMPANY
GEORGIA	GEORGIA POWER
MARYLAND	BALTIMORE GAS & ELECTRIC COMPANY
NORTH CAROLINA	DUKE POWER COMPANY
SOUTH CAROLINA	SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGINIA	VIRGINIA ELECTRIC & POWER COMPANY
WEST VIRGINIA	APPALACHIAN POWER COMPANY
EAST NORTH CENTRAL	
ILLINOIS	COMMONWEALTH EDISON COMPANY
INDIANA	PUBLIC SERVICE COMPANY OF INDIANA
MICHIGAN	DETROIT EDISON COMPANY
OHIO	OHIO POWER COMPANY
WISCONSIN	WISCONSIN ELECTRIC POWER COMPANY
EAST SOUTH CENTRAL	
ALABAMA	ALABAMA POWER COMPANY
KENTUCKY	LOUISVILLE GAS & ELECTRIC COMPANY
MISSISSIPPI	MISSISSIPPI POWER & LIGHT COMPANY
WEST NORTH CENTRAL	
IOWA	IOWA POWER & LIGHT COMPANY
KANSAS	KANSAS GAS & ELECTRIC COMPANY
MINNESOTA	NORTHERN STATES POWER COMPANY
MISSOURI	UNION ELECTRIC COMPANY
NORTH DAKOTA	OTTER TAIL POWER COMPANY
SOUTH DAKOTA	NORTHWESTERN PUBLIC SERVICE COMPANY
WEST SOUTH CENTRAL	
ARKANSAS	ARKANSAS POWER & LIGHT COMPANY
LOUISIANA	GULF STATES UTILITIES COMPANY
OKLAHOMA	OKLAHOMA GAS & ELECTRIC COMPANY
TEXAS	HOUSTON LIGHTING & POWER COMPANY
MOUNTAIN STATES	
ARIZONA	ARIZONA PUBLIC SERVICE COMPANY
COLORADO	PUBLIC SERVICE COMPANY OF COLORADO
IDAHO	IDAHO POWER COMPANY
MONTANA	MONTANA POWER COMPANY
NEVADA	NEVADA POWER COMPANY
NEW MEXICO	PUBLIC SERVICE COMPANY OF NEW MEXICO
UTAH	UTAH POWER & LIGHT COMPANY
WYOMING	CHEYENNE LIGHT, FUEL & POWER COMPANY
PACIFIC	
CALIFORNIA	SOUTHERN CALIFORNIA EDISON COMPANY
OREGON	PACIFIC POWER & LIGHT COMPANY
WASHINGTON	PUGET SOUND POWER & LIGHT COMPANY

EXHIBIT B-3

KILOWATT HOUR SALES TO ULTIMATE CUSTOMERS
INVESTOR-OWNED UTILITIES AS PERCENT OF
TOTAL INDUSTRY
1973



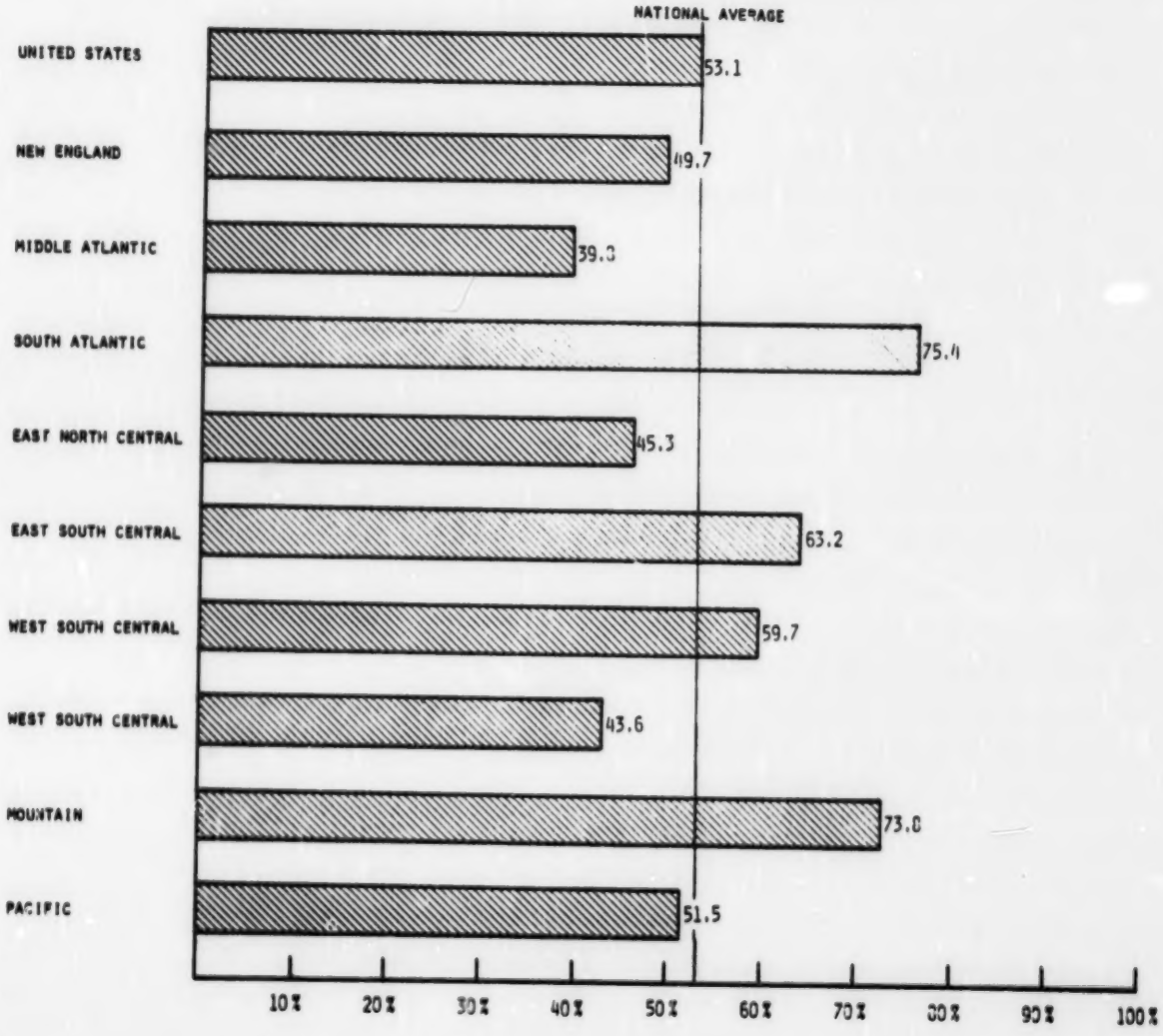
Source: EEI Statistical Yearbook of the Electric Utility Industry
TBS Sample of Investor-Owned Utility Systems

those regions where publicly owned utilities are significant factors, the percentage of investor-owned utilities is significantly below the national average. For example, investor-owned utilities represent less than one-third of the sales to ultimate consumers in the East South Central region, where the Tennessee Valley Authority dominates. Likewise, the exclusion of investor-owned utilities from Nebraska is reflected in the West North Central region. The dominance of publicly owned hydro-electric projects in the Northwest can be seen in the Mountain and Pacific regions.

Given the market penetration of investor-owned utilities, the TBS sample represents a substantial portion of kilowatt hour sales to ultimate consumers of investor-owned utilities within each region during 1973. As can be seen in Exhibit B-4, the sample of utility systems represents more than 53 percent of the sales of investor-owned utilities within the contiguous United States, ranging from a low of 40 percent in the Middle Atlantic region to a high of 75 percent in the South Atlantic region. These differences in coverage reflect the differing proportions of the population served by the largest utility system within the various states. Therefore, regions wherein a single utility system represents most of the customers within a state--for example, the South Atlantic and Mountain regions--are well represented within the TBS sample. On the other hand, those regions wherein states tend to have competitive utility systems--such as the Middle Atlantic, East North Central, and West South Central regions--have relatively low representation.

EXHIBIT B-4

KILOWATT HOUR SALES TO ULTIMATE CUSTOMERS
TBS SAMPLE AS PERCENT OF
INVESTOR-OWNED UTILITIES
1973



Source: EEI Statistical Yearbook of the Electric Utility Industry
TBS Sample of Investor-Owned Utility Systems

Overall, the TBS sample of 47 electric utility systems covers more than 40 percent of the total kilowatt hours sold to ultimate consumers within the United States during 1973, ranging from a low of 20 percent in the East South Central region to a high of nearly 65 percent in the South Atlantic region.

For each company within the statistical sample, TBS requested historical information for the years 1972 through 1974, including the following items:

- annual report and statistical supplement (if any);
- Uniform Statistical Report (a document submitted to the American Gas Association, the Edison Electric Institute, and financial analysts on an annual basis);
- description of rate schedule;
- description of fuel adjustement clause; and
- summary of recent rate requests.

This information was supplemented by TBS analysis of the Federal Power Commission's Form 423, which is a monthly report of cost and quality of fuels purchased for steam-electric generation plants.

While no attempt was made to apply sophisticated sampling techniques when specifying the TBS sample, the broad coverage most likely reflects accurately rate increases within the investor-owned sector of the electric utility industry. Extrapolating this sector's rate increases to the total industry implies that rate increases within the publicly owned utilities equaled those within

the investor-owned sector. This assumption cannot be verified at this time.

Field Interview Sample

As part of its analysis, TBS conducted field interviews with rate managers and other key executives of 18 investor-owned utility systems throughout the country. These interviews were conducted to provide anecdotal information from utility rate managers. Utility executives are daily faced with the realities of utility revenue requirements, and, therefore, their perceptions of the major underlying causes of recent rate requests were invaluable in this research.

In most cases, the field interviews with utility rate managers followed the collection of quantitative data on each utility system and concentrated on anticipated rate requests, efforts to document the underlying reasons for additional revenues, and cost and operating experience with pollution control equipment.

Investor-owned utility systems selected for these interviews were the two largest investor-owned utilities within each of the Bureau of Census geographic divisions (excluding Alaska and Hawaii), with the additional criterion that no more than one utility system from any given state would be interviewed. Prior to conducting these interviews, TBS modified this sample to increase the value of the survey to EPA by including three utility systems which have had experience with the operation of

pollution control equipment, namely:

- Arizona Public Service Company
- Duquesne Light Company
- Kansas City Power and Light Company

The complete list of utilities visited as part of this research are detailed in Exhibit B-5.

Exhibit B-5

TBS SAMPLE FOR FIELD INTERVIEWS*

	INTERVIEW COMPLETED
NEW ENGLAND	
Connecticut Power & Light Company	yes
Massachusetts Electric Company	yes
MIDDLE ATLANTIC	
Consolidated Edison	no
Duquesne Light Company	yes
SOUTH ATLANTIC	
Duke Power Company	no
Florida Power & Light Company	no
EAST NORTH CENTRAL	
Commonwealth Edison Company	yes
Detroit Edison Company	yes
EAST SOUTH CENTRAL	
Alabama Power Company	yes
Louisville Gas & Electric	yes
WEST NORTH CENTRAL	
Kansas City Power & Light Company	yes
Union Electric Company	yes
WEST SOUTH CENTRAL	
Gulf States Utilities	yes
Houston Lighting & Power Company	yes
MOUNTAIN STATES	
Arizona Public Service Company	yes
Public Service Company of Colorado	yes
PACIFIC	
Pacific Power & Light Company	yes
Southern California Edison Company	yes
Puget Sound Power & Light Company*	yes

**Time constraints have limited the field research to 15 of the 18 pre-selected utility systems. In addition, Puget Sound Power and Light, which is the largest electric utility in the state of Washington, was included.*